BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1142

In the Matter of	**)**
Application of Duke Energy Progress,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF JUSTIN R. BARNES ON BEHALF OF NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND CURRENT POSITION.

A. Justin R. Barnes, 401 Harrison Oaks Blvd., Suite 100, Cary, North Carolina, 27513. My current position is Director of Research with EQ Research LLC.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND OCCUPATIONAL BACKGROUND.

A. I obtained a Bachelor of Science in Geography from the University of Oklahoma in Norman in 2003 and a Master of Science in Environmental Policy from Michigan Technological University in 2006. I was employed at the North Carolina Solar Center at N.C. State University for more than five years, where I worked on the *Database of State Incentives for Renewables and Efficiency ("DSIRE")* project, and several other projects related to state renewable energy and efficiency policy.

In my current position I coordinate EQ Research's various research projects for clients, assist in the oversight of EQ Research's electric industry regulatory and general rate case tracking services and perform customized research and analysis to fulfill client requests. I have testified before the Public Service Commission of South Carolina, the Oklahoma Corporation Commission, the Colorado Public Utilities Commission, the Utah Public Service Commission, and the Public Utility Commission of Texas as an expert in distributed generation ("DG") policy, rate design, and cost of service. My *curriculum vitae* is attached as Exhibit JRB-1.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION")?

A. No.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the North Carolina Sustainable Energy Association ("NCSEA").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses three issues with the rates application put forth by Duke Energy Progress ("DEP" or "the Company"), all of which relate to rate design and cost of service, as follows:

1. The Company's proposed increases in fixed customer charges, from a perspective of ratemaking principles and the proper determination and allocation of customer-related costs.
2. The Company's classification of past and anticipated coal ash remediation costs as related to production demand rather than energy.
3. The Company's discussion of its plans for the deployment of advanced metering infrastructure ("AMI").

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S PROPOSED CUSTOMER CHARGES.

A. I recommend that the Commission reject the dramatic increases to customer charges that DEP has proposed and retain the current customer charge levels. If the Commission does find that any increases are justified, those increases should

be capped at the overall percentage increase in revenue by customer class. My recommendation is based on demonstration that the Company's customer charge proposals are:

1. Extreme by numerous objective measures in comparison to state and national ratemaking trends.
2. Based on a distribution cost classification methodology, the Minimum System Method, that is logically flawed, and even assuming it is valid, has been improperly executed by DEP.
3. Damaging to customer incentives to pursue energy efficiency and DG, which has the effect of increasing future risks to ratepayers at the precise time when the consequences of those risks could not be more apparent.

I further recommend that the Commission establish a methodology for determining customer-related costs that reflects cost causation and results in consistency between utilities.

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S PROPOSED CLASSIFICATION AND ALLOCATION OF COAL ASH REMEDIATION COSTS.

A. I recommend that the Commission direct the Company to classify all costs associated with coal ash remediation as energy-related, and that this change be reflected in revised class revenue allocations. My recommendation is based on the fact that coal ash is a by-product of energy production, and its creation bears little or no relationship to system peak demand. Because it is directly tied to the use

and consumption of coal as a fuel, the principle of cost causation indicates that it should be classified as energy-related.

Q. PLEASE SUMMARIZE AND EXPLAIN YOUR RECOMMENDATIONS TO THE COMMISSION ON THE COMPANY'S AMI DEPLOYMENT PLAN.

A. I recommend that the Commission conduct a thorough review of the DEP's AMI deployment plan and how it will affect customer rates generally and the rates for individual rate classes. I recommend that this review take place as part of the larger grid modernization proceeding recommended by NCSEA Witness Golin given the cross-section of issues involved, and incorporate the recommendations of NCSEA Witness Murray regarding customer data access, tools, and related investments. My recommendation is based on the profound lack of detail and analysis the Company has presented with respect to future rate designs or options, how they will affect customers, and how they will be designed and implemented to result in system cost savings and opportunities for customer savings.

II. DEP'S CUSTOMER CHARGE PROPOSAL AND ANALYSIS OF CUSTOMER-RELATED COSTS.

Q. PLEASE DESCRIBE THE COMPANY'S RATE PROPOSAL WITH RESPECT TO FIXED CUSTOMER CHARGES.

A. DEP is seeking dramatic increases in fixed customer charges for all customer classes. The amounts vary by class and percentage, but in all cases the percentage increase exceeds the percentage increase in class revenue requirements. In other words, the proposed charges increase the percentage of total class revenue

recovered by a fixed monthly charge and not in a variable charge. Table 1 below sourced from Exhibit No. 1 of the Direct Testimony of Steven Wheeler ("Wheeler Direct") depicts the proposed increases.[1]

Table 1: Company Customer Charge Proposed Rates By Class

Rate Class	Current Customer Charge	Proposed Customer Charge	Rate Change	Percent Change
Residential	$11.13	$19.50	$8.37	75%
Small General Service	$16.45	$22.50	$6.05	37%
SGS-TOU-CLR	$16.45	$22.50	$6.05	37%
Medium General Service	$20.32	$30.00	$9.68	48%
Large General Service	$154.85	$204.00	$49.15	32%
Seasonal and Intermittent	$20.32	$30.00	$9.68	48%
Sports Field Lighting	$20.32	$30.00	$9.68	48%

Q. DO YOU AGREE THAT THE COMPANY'S PROPOSAL FOR CUSTOMER CHARGES IS REASONABLE?

A. No. I object to the Company's proposal for several reasons. First, the proposed charges and proposed increases are extreme by multiple measures, and violate the principle of gradualism in utility ratemaking. This is true in particular for the proposed increase in the residential customer charge. Second, the Company's derivation of the customer-specific costs used to derive the charges, specifically, the use of the Minimum System Method for classifying distribution costs is flawed in both methodology and execution. Third, if adopted they will substantially dilute consumers' ability to control their energy costs and their incentive to save energy through behavioral changes or investments in energy

[1] Exhibit No. 1 of the Direct Testimony of Steven Wheeler contains additional columns that have not been included in Table 1. Footnotes contained in Wheeler Exhibit No. 1 have also been omitted.

efficiency and DG. I discuss each of these criticisms in more detail in the following subsections.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO CUSTOMER CHARGES?

A. I recommend that the current customer charges be maintained. In the alternative, should the Commission believe it is necessary to increase customer charges, they should only be increased by the percentage increase in the overall revenue requirements adopted for each class. I strongly recommend that the Commission take the former approach and maintain customer charges at their current levels.

A. The Company's Proposed Customer Charge Increases are Extreme.

Q. IN WHAT WAYS IS THE COMPANY'S CUSTOMER CHARGE PROPOSAL EXTREME?

A. Before elaborating, I must clarify that my assessment focuses on the residential class both because the Company's proposal is the most extreme for this class, and because the residential class is more amenable to comparisons across states and utilities than other customer classes. That said, the increases proposed for other classes are clearly well in excess of overall rate increases across all classes and can consequentially be labeled as extreme.

The proposed customer charge for the residential class is extreme insofar as it would result in:

1. Customer charges far in excess of those in place for other investor-owned utilities ("IOUs") in North Carolina.

2. Customer charges far in excess of those in place for other Duke Energy Corporation-affiliated utilities.
3. Customer charges far in excess of the national average.
4. Increases far in excess, both in monetary and percentage terms, of increases approved by regulators in other states during the last three years.

Q. HOW DID YOU ARRIVE AT THE CONCLUSIONS ABOVE AND WHAT EVIDENCE DO YOU PRESENT TO SUPPORT THESE CLAIMS.

A. I conducted a review of current residential customer charges for 165 IOUs in 49 states and the District of Columbia.[2] The utilities in this survey encompass all major IOUs and nearly all smaller IOUs in each state, thus it presents a comprehensive national picture of residential fixed charges. I also conducted a review of adopted increases in residential customer charges for IOU general rate case applications filed since July 2014. A total of 106 general rate cases are represented in this sample, though the total number of utilities is lower because several utilities had multiple rate cases during this time frame. Consequently, the sample of adopted increases reflects these utilities more than once. Both datasets are current as of October 2, 2017. Exhibit JRB-2 contains the full results of both of these surveys.

Q. PLEASE SUMMARIZE THE RESULTS OF THE RESEARCH YOU DESCRIBE ABOVE.

A. There are a number of telling statistics that arise from my research, as follows:

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[2] Nebraska is the only state not represented in this survey. Nebraska is unique in that it is the only state served entirely by consumer-owned utilities not subject to external rate regulation.

1. The Company's current residential fixed charge ranks 63rd out of 165 utilities, meaning that it is already higher than 62% of the utilities in my survey.
2. The Company's current residential fixed charge of $11.13/month is already $0.54/month higher than the national average of $10.59/month.
3. If adopted, the Company's proposed rate of $19.50/month would rank it 11th out 165 utilities, with only 6% of the sample utilities having higher residential customer charges.
4. If adopted, the Company's residential fixed charge would be $8.91/month above the national sample average.
5. The average residential fixed charge increase adopted in general rate cases included in the national sample was $1.11/month, or 14.09%. By comparison, the Company proposes to increase its residential customer charge by $8.37/month or 75%. Thus it amounts to a monetary increase of more than seven times the average, and a percentage increase of more than five times the average.
6. The proposed increase of $8.37/month in the residential customer charge is substantially higher than any residential fixed charge increase adopted by regulators in other states in rate cases filed in the last three years.
7. The Company's current fixed charge already ranks 2nd out of eight Duke Energy Corporation-affiliate utilities and is $2.87/month above the Duke Energy affiliate average of $8.26/month (excluding DEP in North Carolina). If the proposed increase were adopted, the charge would rank

1st by a wide margin, $11.24/month above the Duke Energy affiliate average.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE RESULTS OF YOUR RESIDENTIAL FIXED CHARGE ANALYSIS?

A. Yes. Three of the utilities with fixed charges higher than what DEP has proposed are located in New York. The New York Public Service Commission ("NYPSC") is in the process of broadly reconsidering utility rates for residential customers, including the role of fixed charges.[3] In addition, the charge listed for one utility, Hawaii Electric Light is actually a minimum bill rather than a fixed charge.[4] This is a significant distinction because the true fixed charge ($10.50/month) is substantially lower than what DEP proposes. Finally, three utilities, Public Service Oklahoma, Rocky Mountain Power Wyoming, and Montana-Dakota Utilities Wyoming have extremely rural service territories where fixed infrastructure serves a relatively small number of customers. Consequently, their systems are not necessarily comparable to DEP's. Given these facts, DEP's proposal is actually even more extreme than the information in Exhibit JRB-2 suggests.

Q. ARE THE COMPANY'S PROPOSED INCREASES TO THE RESIDENTIAL AND OTHER CLASS CUSTOMER CHARGES CONSISTENT WITH THE PRINCIPLE OF GRADUALISM?

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[3] See for example, NYPSC Matter No. 17-01277. In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design. *Staff Scope of Study to Examine Bill Impacts of a Range of Mass Market Rate Reform Scenarios* (October 3, 2017).
[4] Hawai'i Electric Light ("HELCO"), Schedule R, available at https://www.hawaiianelectric.com/my-account/rates-and-regulations/hawaii-electric-light-rates.

A. Absolutely not. Company Witness Wheeler states that gradualism is an important consideration in ratemaking.[5] I certainly agree with this statement. However, the Company's proposal with respect to customer charges is inconsistent with this ratemaking principle. As evidenced by both the amount and percentage of the proposed increase in the residential fixed charge, the Company's proposal clearly does not represent "gradualism" as practiced by regulators in other states.

B. The Proposed Customer Charge Increases Would Dilute Customers' Motivations to Pursue Energy Efficiency and DG.

Q. HOW DO FIXED CHARGES AFFECT CUSTOMER BEHAVIOR WITH RESPECT TO ENERGY EFFICIENCY?

A. Higher fixed customer charges result in more revenue being collected under fixed fees, which in turn reduces the energy and demand rates necessary to raise the remaining portion of the revenue requirement. Lower variable charges provide less of an incentive for customers to reduce their demand or overall energy use. In effect, customers see less savings as a result of conservation, so they are less motivated to reduce their overall energy usage or demand.

Q. HOW WOULD THE COMPANY'S PROPOSAL FOR INCREASING CUSTOMER CHARGES AFFECT ENERGY USAGE RATES?

A. For the residential sector, the fixed charge increase translates to roughly 0.75 ¢/kWh based on the test year number of residential customers and energy sales used in the Company's cost of service study. This figure is derived by multiplying the proposed monthly increase of $8.37 by the number of 2016 residential

[5] Direct Testimony of Steven Wheeler, p. 8.

customer bills, resulting in a residential customer charge revenue increase of roughly $116.5 million. Dividing this revenue increase by test year sales of roughly 15.5 million MWh results in the 0.75 ¢/kWh figure.[6]

Q. HOW WOULD SUCH A CHANGE AFFECT CUSTOMER SAVINGS FROM DG INSTALLATION OR ENERGY EFFICIENCY?

A. The effect would be meaningful. The National Renewable Energy Laboratory ("NREL") PVWatts calculator estimates that a well-sited 4 kilowatt ("kW") PV system in the Raleigh, North Carolina area will produce roughly 5,700 kWh during the first year.[7] If degradation of 0.5% annually is considered, the 20-year annual average system production would amount to roughly 5,100 kWh. Based on this estimate, over 20 years the customer would save $750 less under DEP's residential customer charge proposal relative to the current fixed charge rate. This assumes that DEP does not seek further dramatic increases in the fixed customer charge.

The savings reduction impacts for energy efficiency would be smaller on a per customer basis because energy efficiency investments do not typically result in the same level of annual energy savings as DG. Nevertheless, if the fixed charge increase reduced overall residential class energy efficiency savings by only 1%, the level of forgone savings for the residential class as a whole would exceed $1 million annually. The diluted conservation incentive as reflected in utility rates would have to be made up through incentives via energy efficiency programs in order to achieve the same outcomes.

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[6] Values sourced from NCUC Form E-1 Item 45E 1CP 2016 Adj. Prop. Unit Costs.
[7] Estimate uses default PVWatts values. PVWatts is available at http://pvwatts.nrel.gov/pvwatts.php.

Q. WHAT ARE THE LONG-TERM EFFECTS OF DILUTING INCENTIVES FOR ENERGY CONSERVATION AND DG?

A. The long-term effects with respect to utility rates are difficult to ascertain. Logically, less conservation and less DG leads to higher amounts of utility investment in generation, transmission, and distribution, which in turn places upward pressure on rates.

Beyond this it creates unknown and likely unknowable risks for current and future ratepayers. This proceeding is illustrative of the fact that such long-term risks are not easy to assess. The Company is presently seeking recovery of significant costs associated with coal ash remediation, which comprise a large part of the revenue increase request. These costs were not priced into the rates that existed during the time period when coal ash accumulated at storage sites. Regardless of the reasons for this, or what was deemed reasonable and prudent at the time, this amounts to a market failure in hindsight. In other words, had rates reflected these future costs, customers would have purchased less electricity and in theory the result would have been more economically efficient.

Instead, assuming that the Commission approves some form of recovery for coal ash remediation costs, current customers will be saddled with costs that they had no opportunity to avoid. Ultimately, diluting incentives for energy efficiency and DG runs against a policy of avoiding future costs or the risk of future costs. Especially under the current circumstances, I do not believe that this would be a wise course of action.

C. The Minimum System Method is Not an Appropriate Methodology for Classifying Distribution Costs.

Q. PLEASE DEFINE CUSTOMER-RELATED COSTS.

A. Company Witness Hager defines customer-related costs as "costs incurred primarily as a result of the number of customers being served."[8] I do not wholly agree with this definition, specifically the use of the word "primarily". A more appropriate definition of customer-related costs would be the definition used by the Regulatory Assistance Project ("RAP"), which defines customer-related costs as "[c]osts that vary *directly* with the number of customers."[9] [Emphasis added.]

Q. HOW DOES THE COMPANY ARRIVE AT ITS CALCULATION OF CUSTOMER-RELATED COSTS?

A. There are several elements. The Company classifies as all costs related to meters and services, in Federal Energy Regulatory Commission ("FERC") accounts 369-370 as customer-related. It also classifies a large portion of the costs associated with FERC accounts 364-368, relating to poles, towers and fixtures (Account 364), overhead conductors and devices (Account 365), underground conduit (Account 366), underground conductors and devices (Account 367), and line transformers (Account 368) as customer-related. Accounts 364-368 are classified based on what is often referred to as the Minimum System Method.[10]

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[8] Direct Testimony of Janice Hager, p. 6.
[9] J. Lazar and W. Gonzalez, *Smart Rate Design for a Smart Future*, p. 36, REGULATORY ASSISTANCE PROJECT (2015), available at: http://www.raponline.org/document/download/id/7680.
[10] Duke Energy Progress Response to NCSEA Data Request No. 10-20 ("DEP Response to NCSEA DR10-20").

The calculated customer costs also include operations and maintenance ("O&M") associated with these portions of the distribution system in the same proportions. Finally, the category includes a portion of administration and general plant in-service and associated O&M, uncollectables, and incremental Customer Connect O&M expenses.[11]

Q. PLEASE DESCRIBE THE MINIMUM SYSTEM METHOD AND HOW IT AFFECTS RATEMAKING.

A. The theory behind the Minimum System Method is that the distribution system is designed to not only serve customer demand, but also to connect customers regardless of their need for electricity. That is, it assumes that some costs of the shared distribution system are incurred solely for the purpose of connecting each customer. It generally relies on an examination of the book costs associated with each cost category (e.g., poles and towers) to establish the costs associated with a hypothetical distribution system that serves virtually no load.

In ratemaking, the results of a minimum system analysis influence how distribution costs are allocated to different rate classes. This is because the allocators based on the number of customers in a class differ from those based on demand. Generally speaking, the result of more costs being classified as customer-related is a larger revenue requirement for classes with the largest number of customers (e.g., the residential class). In practice, it also has a cascading effect because other cost allocators rely in part on the distribution-related allocators. Finally, it may also influence how revenue is collected in the

[11] Duke Energy Progress Response to SELC Data Request No. 1-13.

form of customer, demand, or energy charges to the extent that charges are based on the classification of costs (i.e., customer costs collected via customer charges).

Q. WHAT EFFECT DOES THE USE OF THE MINIMUM SYSTEM METHOD HAVE ON THE COMPANY'S RESIDENTIAL REVENUE REQUIREMENTS AND CALCULATED UNIT COSTS?

A. According to the Company's analysis, which I have attached as Exhibit JRB-3, if the Minimum System Method is removed from the cost of service study, the calculated residential customer unit cost decreases from $27.82/month to $8.54/month.[12] It also reduces the proposed revenue increase for the residential class by roughly $23.8 million from $264.718 million to $240.906 million.[13] The adjustment prompts corresponding shifts in revenue requirements for other classes as well as changes to demand-related unit costs.

Q. IS THE MINIMUM SYSTEM METHOD GENERALLY ACCEPTED AS AN APPROPRIATE METHOD FOR CLASSIFYING DISTRIBUTION SYSTEM COSTS?

A. No. The Minimum System Method is based on the faulty premise that customers will pay to connect to the distribution grid even if they do not intend to use any electricity. In reality, a customer that has no demand for electricity would have no need to be connected to the distribution system. Distribution costs are caused by that demand, not by the presence of the customer. A zero or minimum demand

[12] Duke Energy Progress Supplemental Response to SELC Data Request No. 1-5(a) Attachment 1, No Min NCUC Form E-1, Item 45E 1CP 2016 Adj Prop Unit. ("DEP Supplemental Response to SELC DR1-5(a)").
[13] Calculated based on data contained in the Direct Testimony of Laura Bateman Exhibit No. 2, and the class revenue increase under a no minimum system distribution cost allocation from DEP Supplemental Response to SELC DR1-5(a).

customer of the type represented by the Minimum System Study simply does not exist. In the Company's own words "All feeders are constructed to meet the unique load and customer requirements of the area being served."[14]

Even if one stipulates that items such as poles themselves have no load-carrying or demand-serving capability, they are still an integral part of a system designed to serve customer demand. Thus their cost remains tied to the need to serve customer demand. Taken to its furthest extent, the flawed premise underlying the Minimum System Method effectively assumes that any cost not proven to fall into another category must be customer-related. Dr. James Bonbright discusses this line of thinking in his seminal work *Principles in Public Utility Rates*, where he cautions against "using the category of customer costs as a dumping ground for costs that [the cost analyst] cannot plausibly impute to any of his other cost categories."[15]

Q. DO OTHER STATES USE THE MINIMUM DISTRIBUTION SYSTEM METHOD FOR ALLOCATING DISTRIBUTION COSTS AND SETTING CUSTOMER CHARGES?

A. Many states confine the definition of "customer" costs to those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. A report commissioned by the National Association of Regulatory Utility Commissioners ("NARUC") found that this "basic customer method" (100% demand for shared

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[14] Duke Energy Progress Response to NCSEA Data Request No. 11-8(c) ("DEP Response to NCSEA DR11-8(c)").
[15] Dr. James Bonbright, *Principles of Public Utility Rates*, p. 349, Columbia University Press (1961).

distribution facilities and 100% customer for meters and services) was the most common approach at the time of the report:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand-related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[16]

In other states, some portion of the shared distribution system may be considered customer-related and allocated on that basis, but the methodology used can vary from state to state.

Rate design practices are likewise variable because rate design involves a balance of numerous competing objectives, such as fairness, stability, effectiveness at meeting revenue requirements, cost causation and customer acceptance. The balancing reflects the fact that these objectives are frequently in conflict with one another. Regardless, as evidenced by data presented in Exhibit JRB-2, it is clear that regulators have only rarely adopted residential fixed charges at the level proposed by the Company, and no regulatory commission has approved a monetary increase as large as what the Company proposes in rate case applications filed during the last three years.

Q. HAS THE MINIMUM SYSTEM METHOD BEEN APPROVED FOR USE IN NORTH CAROLINA?

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[16] F. Weston, et al., *Charges for Distribution Service: Issues in Rate Design*, p. 19, REGULATORY ASSISTANCE PROJECT (2000), available at http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

A. I am aware that all three IOUs in North Carolina have used the Minimum System Method in their cost of service studies in recent rate cases. It is not clear to me whether NCUC has ever formally endorsed the method, or the manner in which DEP performs its minimum system study. However, it is clear that DEP's methodology has changed considerably over time so as to place greater portions of the distribution system within the customer cost category. For instance, in its current study DEP reclassified the primary portion of underground conduit from 6% customer-related to 100% customer-related.[17] This change has certainly not been endorsed by the Commission. I will discuss the Minimum System Study itself in more detail in the subsequent section.

It is also clear that the manner in which DEP conducts the study is substantially different from how Dominion Energy North Carolina ("Dominion") does, resulting in a much larger portion of the distribution system being classified as customer-related. For instance, in its 2016 general rate case, Dominion classified only 31.08% of secondary poles in FERC Account 364 as customer related.[18] DEP has classified 95.9% of secondary poles in FERC Account 364 as customer related.[19] Similar differences are evident for other distribution accounts, contributing to Dominion's estimate of residential class customer unit costs of \$12.07/month.[20] By contrast, DEP derived residential class customer unit costs of

[17] DEP Response to NCSEA DR10-20.
[18] NCUC Docket No. E-22, Sub 532. NCUC Form E-1, 45F, p. 121.
[19] DEP Response to NCSEA DR10-20, Attachment B (detailing customer and demand percentages by FERC account).
[20] NCUC Docket No. E-22, Sub 534.Exhibit GAP-1. Schedule 6, p. 1.

\$27.82/month.[21] While there are other factors that play a role in creating this difference, DEP's Minimum System Study is undoubtedly is a large contributor.

Q. IS THE MINIMUM SYSTEM METHOD ENDORSED BY NARUC?

A. No. The NARUC Electric Utility Cost Allocation Manual ("NARUC Manual") refers to the Minimum System Method as *one* method of classifying distribution costs, but it does not endorse any method in particular. In fact, the preface expressly states, in the context of the objectives:

> The writing style should be non-judgmental, not advocating any one particular method, but trying to include all currently used methods with pros and cons.[22]

The section on distribution cost allocation protocols goes on to note that the results are directly related to the assumptions used, such as how the minimum size distribution equipment is selected. Furthermore, the NARUC Manual includes cautionary statements regarding the use of the minimum system, among them that the "minimum-size distribution equipment has a certain load-carrying capability, which can be viewed as a demand-related cost." [23]

Finally, it is also worth noting that the NARUC Manual dates from 1991, while the NARUC-commissioned report on state distribution system classification that I mentioned previously is more recent, having been published in 2000. All of this serves to demonstrate that the Minimum System Method should not be regarded as the commonly accepted or prevailing method of distribution system cost classification.

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[21] Wheeler Direct, Exhibit No. 1.
[22] NARUC. Electric Utility Cost Allocation Manual. p. ii. 1991.
[23] Ibid. p. 95.

D. The Company's Minimum System Study is Itself Flawed.

Q. PLEASE DESCRIBE HOW THE COMPANY PERFORMS ITS MINIMUM SYSTEM STUDY.

A. The Company's study defines the percentage of costs attributable to the customer based on the ratio between the minimum system and a "standard system". The minimum system is described as being based on an "average feeder."[24] The so-called standard system is not expressly defined. As I have previously mentioned, in this version of the study, the Company elected to categorically define all primary underground conduit as 100% customer-related, from the prior classification of 6% customer-related and 94% demand-related.

Q. WHAT PROBLEMS HAVE YOU IDENTIFIED WITH THE WAY THE COMPANY HAS CONDUCTED ITS MINIMUM SYSTEM STUDY?

A. First, I will reiterate that I disagree with the use of the Minimum System Method for classifying distribution costs altogether. That said, if the Commission were to accept its use on a conceptual level, I see several issues with the methodology which all serve to distort the results and increase the portion of the distribution system classified as customer-related.

First, the Company's cost of service study is intended to reflect embedded costs as of the test year. The Company's Minimum System Study appears to use current equipment and currently installed costs rather than the minimize equipment that was historically installed (i.e., what is on the system now). I cannot definitively say that this is the case because the Company failed to respond

[24] DEP Response to NCSEA DR10-20, Attachment 1, p. 2.

with this information despite a data request from NCSEA expressly asking for this information.[25] However, the process described in response to a data request from NCSEA indicates that the study reflects current equipment and costs based on the development of work order estimates by distribution and project planning staff.[26] That implies that current equipment and costs are being used in the calculation. This is problematic because it fails to represent the true minimum system, which cannot be greater than the smallest size equipment that was historically installed and continues to exist on the system right now.

Second, the methodology is inconsistent with what the Minimum System Method is intended to evaluate in the first place and departs from the how the method is described in the NARUC Manual. By way of explanation, as I mentioned earlier, DEP's study makes a comparison between an average and standard system. As described in the NARUC Manual, a typical study does not establish a comparison between a minimum and standard system, it simply takes the book cost of the smallest size component for each equipment type (e.g., poles) and multiplies that cost by a number that represents the total system (e.g., number of poles, miles of conductor). That estimate constitutes the customer-related portion.[27] It is a simple formula that does not require the establishment of an average feeder, or a "standard system" cost estimate because neither has any bearing on the minimum size component. The Company's approach is more

[25] See NCSEA DR10-20 and DEP Response to NCSEA DR10-20.
[26] Ibid.
[27] NARUC. Electric Utility Cost Allocation Manual. pp. 90-92.

convoluted and opaque, relying in large part on the determination of the "standard system" which is not adequately identified or explained.

Third, the Company's decision to classify all primary conduit costs as customer-related is not justified. The Company states that this portion of the system was reclassified on the basis that underground facilities are now "standard" because some local governments either mandate or encourage underground distribution facilities.[28] However, the Company's cost of service study clearly shows that on the basis of gross plant in-service, underground lines are a smaller portion of its distribution system than overhead lines, listing the amount of overhead line gross plant in-service at $1.38 billion, while the underground line portion is $1.1 billion.[29]

In addition, the Company was unable to provide information on what portion of underground distribution system is related to customer requests rather than local mandates, stating that its records do not distinguish this characteristic.[30] There is simply no evidence supporting the argument that underground distribution facilities are a standard feature of the distribution system. Unless such mandates are universal, this feature of the system can hardly be considered standard.

Q. BASED ON YOUR REVIEW OF DEP'S MINIMUM SYSTEM STUDY, WHAT ARE YOUR CONCLUSIONS?

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[28] DEP Response to NCSEA DR10-20. Attachment 1, p. 2 .
[29] NCUC Form E-1, Item 45D 1CP Adj. Prop. Unbun. COS., Tab Rate Base NC-1.
[30] Duke Energy Progress Response to NCSEA Data Request No. 11-8(d).

A. I have serious concerns about whether the study is accurate for several overarching reasons. The results would force one to conclude that nearly all distribution costs are incurred on the basis of the number of customers being served rather than their demand for energy. Nowhere is this more evident than in the classification of the secondary portion of the system, which is classified as follows:[31]

- Poles, Towers and Fixtures (Account 364): 95.9% customer-related.
- Overhead Conductors and Devices (Account 365): 100% customer-related.
- Underground Conduit (Account 366): 100% customer-related.
- Underground Conductors and Devices (Account 367): 97.9% customer-related.

The implication of these figures is that DEP's secondary distribution system is effectively uniform (i.e., the minimum system is the standard system) with virtually no variation based on the type of customers being served, their demand, or location (e.g., urban or rural). It is hard to reconcile this conclusion with the Company's own statement that "[a]ll feeders are constructed to meet the unique load and customer requirements of the area being served."[32]

Furthermore, the differences between the results of DEP's study and Dominion's equivalent study are obvious and meaningful. While I have not evaluated Dominion's study in great detail, the fact that the results are so

[31] DEP Response to NCSEA DR10-20. Attachment 2, Summary Tab, Column N.
[32] DEP Response to NCSEA DR11-8(c).

dramatically different points to significant differences in methodology that require careful scrutiny.

Finally, the fact is that the Company's Minimum System Study is being used to justify dramatic increases in fixed customer charges, which benefit the Company by fixing a larger portion of its revenue. A reasonable observer might question whether the Company has found a way to puts its thumb on the scales to inflate the classification of customer-related costs. Case in point would be the Company's reclassification of primary class underground conduit as 100% customer-related, which it has failed to adequately justify.

Q. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO DEP'S MINIMUM SYSTEM STUDY?

A. The Commission should reject this method for the allocation for distribution costs, and as a consideration in rate design. If the Commission chooses not to categorically reject it, the results should be nevertheless be disregarded for the purposes of the current proceeding and the Commission should establish a consistent system that aligns with cost causation.

III. DEP'S CLASSIFICATION OF COAL ASH REMEDIATION COSTS

Q. DO YOU WISH TO RAISE ANY OTHER ISSUES ASSOCIATED WITH THE COMPANY'S COST OF SERVICE STUDY?

A. Yes. I believe the Company has incorrectly classified coal ash remediation costs as related to production demand. This classification is reflected in the standard E-1 Item 45D detailing the customer class allocation of the roughly $52.1 million

annual amortization expense and $129.1 million in ongoing O&M costs associated with coal ash remediation.[33]

Q. WHY IS THIS CLASSIFICATION INCORRECT?

A. Coal ash is a by-product of fuel, namely coal. Fuel costs should be classified as energy-related costs, not demand-related costs. In this instance, the volume of coal ash that creates remediation costs is directly associated with the amount of electricity produced and the volume of coal used to product this electricity. Remediation costs should therefore be classified as energy-related.

Q. DOES THE COMPANY JUSTIFY ITS CLASSIFICATION OF COAL ASH REMEDIATION COSTS AS RELATED TO PRODUCTION DEMAND?

A. The classification is not addressed in direct testimony. However, in response to a request for information the Company states that the classification is consistent with "how DEP has historically allocated production cost of removal…as well as nuclear decommissioning expense in its prior North Carolina rates and cost of service studies".[34] [35]

Q. DOES THIS EXPLANATION PROVIDE A REASONABLE BASIS FOR THE CLASSIFICATION OF COAL ASH REMEDIATION COSTS AS PRODUCTION DEMAND RELATED?

A. No. It conflates decommissioning of a power plant designed to serve demand with remediation associated with the by-product of a fuel used to produce energy. Moreover, the logic is inconsistent with the testimony of Company Witnesses

[33] Referred to in Bateman Direct. p. 24, lines 10-11 and p. 25 lines 6-8.
[34] Duke Energy Progress Response to SELC Data Request No. 1-6.
[35] Duke Energy Progress Response to SELC Data Request No. 1-7.

Kerin and McGee supporting the recovery of net costs associated with the beneficial reuse of coal ash through the fuel adjustment clause, on the basis that coal ash is a by-product of a fuel.[36] [37] Stated another way, the coal ash would not have been produced but for the use of a specific type of fuel to produce electricity. Furthermore, the amount that was produced is related to the total volume of the coal consumed hour after hour over years, not demand during the peak hour or hours of a given year.

Q. WHAT ARE THE IMPLICATIONS OF CLASSIFYING COAL ASH REMEDIATION COSTS AS DEMAND-RELATED RATHER THAN ENERGY-RELATED?

A. It has two effects. First, it distorts the allocation of revenue requirements between classes because for some classes the energy-related allocators are substantially different than the production demand allocator. Second, it affects the calculated unit costs for demand and energy, which play a role in determining the breakdown of customer rates between demand and energy components.

Q. PLEASE DESCRIBE HOW THE CLASSIFICATION OF COAL ASH REMEDIATION COSTS AS PRODUCTION DEMAND RELATED AFFECTS CLASS REVENUE REQUIREMENTS.

A. For instance, the North Carolina E1 allocator (energy at the source) for the residential class is 41.696% while the production demand ("DP") allocator is 48.271%. For large general service in contrast, the E1 allocator is 22.172% while the DP allocator is 16.275%. The large general service class benefits from an

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[36] Direct Testimony of Jon Kerin. p. 20, lines 14-22.
[37] Direct Testimony of Kimberly McGee, p. 7, lines 9-18.

allocation based on production demand at the expense of the rate classes for smaller customers.[38]

The disconnect from cost causation is further highlighted by the fact that the street lighting service (SLS) class has a 0.00% DP allocator, meaning that the class revenue requirement contains no coal ash remediation costs.[39] The zero allocator occurs because the SLS class operates only during nighttime hours while the system coincident peak used to determine the DP allocator occurred during a daylight hour. So despite the fact that nighttime energy needs associated with the SLS class resulted in the creation of coal ash, the SLS class is not obligated to pay for coal ash remediation if costs are allocated on the basis of production demand.

Q. CAN YOU QUANTIFY THE DIFFERENCES IN CLASS REVENUE REQUIREMENTS ASSOCIATED WITH ALLOCATING THE COAL ASH AMORTIZATION REVENUE REQUIREMENT BASED ON ENERGY RATHER THAN PRODUCTION DEMAND?

A. Yes. Table 2 below shows the Company's proposed allocation based on the DP allocator using a summer single coincident peak method (1CP) compared to an allocation based on energy at the source (E1 allocator). The input data is sourced from the Company's E1 45C (allocators) and 45D (COS adjustments) filings. The values reflect the sum of amortization and expected ongoing O&M, though the statewide totals have been excluded to preserve space in the table.

[38] Numbers taken from E-1 Item 45C, 1 CP Allocation Factors.
[39] Ibid.

Table 2: DP vs. E1 Allocation of Coal Ash Costs

Customer Class	DP Allocation	E1 Allocation	Difference
RES	$87,456,430	$75,545,486	($11,910,944)
SGS	$11,344,764	$9,108,303	($2,236,461)
SGS-CLR	$81,387	$132,933	$51,546
MGS	$52,368,455	$54,068,454	$1,699,999
LGS	$29,486,788	$40,170,370	$10,683,582
SI	$426,019	$257,499	($168,519)
TSS	$15,951	$27,537	$11,586
ALS	$0	$1,404,225	$1,404,225
SLS	$0	$459,269	$459,269
SFL	$0	$5,717	$5,717

The class revenue implications of the classification would actually be far larger in the long term because Table 2 displays only a single year of the five-year amortization, and does not reflect tax-related effects associated with the amortization, which increase this portion of the rates request from $52.1 million in total to $66.5 million. The percentage differences are significant in the context of class base revenue requirements, ranging from 0.21% to 3.23%. If the difference is compared to the requested base increases by class, the difference ranges from 1.60% to 51.15%. The largest effects, in excess of 30%, are in the lighting classes, but they remain significant for larger rate classes (e.g., 16.69% for the LGS class).

Q. HOW DOES THE ALLOCATION BASED ON PRODUCTION DEMAND AFFECT CUSTOMER RATES?

A. The overall class revenue requirement affects overall rates, but the classification also affects the calculated unit costs for demand and energy. It increases the amount of the revenue requirement that is considered to be demand-related,

thereby inflating the calculated demand unit costs (i.e., demand in $/kW-month). As discussed by Company Witness Wheeler, DEP has not directly translated these unit costs to rates, but unit costs are considered in setting demand rates.[40] In other words, even though there is not a 1:1 ratio between demand unit costs and demand rates, all other things being equal, increasing the amount of costs classified as demand-related tends to cause demand rates to increase by a larger percentage than energy rates.

For instance, for the residential TOU-D rate schedule, the demand rate revenue under DEP's proposal would increase by 13.8% while the energy-related revenue would increase by 12.1%. This is despite the fact that, as I've discussed previously, the Company's minimum distribution system study reclassifies a significant portion of distribution costs that were formerly treated as demand related to customer-related.

Q. WHAT EFFECT WOULD THIS HAVE ON CONSUMER BEHAVIOR?

A. As with increases in fixed charges, it dilutes the financial benefit that a customer sees from consuming less energy, whether by making behavioral changes or pursuing investments in energy efficiency or DG. The effect is particularly detrimental to solar DG investments and behavioral changes that reduce overall energy consumption from the grid.

Q. WHAT ACTION SHOULD THE COMMISSION TAKE WITH RESPECT TO THE CLASSIFICATION OF COAL ASH REMEDIATION COST CLASSIFICATION AND ALLOCATION?

[40] Wheeler Direct. p. 8.

A. The Commission should direct DEP to classify all coal ash remediation costs as energy-related now and in the future.

IV. THE COMPANY'S AMI ROLLOUT PLAN

Q. IS THE COMPANY REQUESTING APPROVAL OF COST RECOVERY FOR ITS ADVANCED METERING INFRASTRUCTURE ("AMI") ROLLOUT PLAN IN THIS PROCEEDING?

A. No, not directly. Company Witness Simpson states internal review and approval by the Company's Board of Directors has not yet occurred and that current planning would not commence deployment of AMI until 2018.[41] However, the Company's application does include a request to establish a regulatory asset for the remaining value of existing meters. The Company's depreciation study reflects recovery of the remaining net book value of the existing meters over three years, the expected deployment period for the program.[42]

Q. DO YOU HAVE ANY CONCERNS ABOUT THE COMPANY'S AMI DEPLOYMENT PLAN?

A. Yes. While in principle I am supportive of AMI deployment, portions of the Company's plans to utilize AMI to benefit customers are incomplete or highly vague. This renders the Company's cost benefit analysis of AMI deployment incomplete as well. The rollout should not be permitted to commence until these issues have been investigated and resolved.

Q. HOW DOES DEP DESCRIBE THE BENEFITS OF AMI DEPLOYMENT TO CUSTOMERS?

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[41] Direct Testimony of Robert Simpson, p. 29, lines 5-7. ("Simpson Direct")
[42] Bateman Direct. p. 19, lines 9-13.

A. The Company's discussion of benefits is spread across Company Witnesses Fountain, Simpson, and Wheeler. I have consolidated how these witnesses discuss AMI benefits below:

- Customer access to more detailed energy use information. (Simpson)
- Improved efficiency in storm restoration efforts. (Simpson)
- Reduced meter reading expenses due to remote meter reading capability. (Simpson)
- Increased convenience to customers with respect to switching power on and off. (Simpson) [43]
- Allowing the development of "innovative" rate designs that provide "real time" price signals. (Wheeler)[44]
- The availability of new programs that provide customers with "enhanced convenience, transparency, choice, and control." (Fountain) [45] The Company elaborated on this in response to a data request, indicating that current plans for these programs are confined to a "Pick You Due Date" and usage alert feature. [46]

Company Witness Hunsicker also discusses how the Company's proposal to upgrade its Customer Information System ("CIS") would be integrated with

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[43] Direct Testimony of Robert Simpson, pp. 29-31.
[44] Wheeler Direct. p. 9, lines 10-23.
[45] Direct Testimony of David Fountain, p. 37, lines 3-6.
[46] Duke Energy Progress Response to NCSEA Data Request No. 3-8.

AMI deployment but does not identify additional customer benefits beyond those described by other witnesses.[47]

Q. DO YOU AGREE THAT AMI DEPLOYMENT HAS THE POTENTIAL TO PROVIDE THE BENEFITS DESCRIBED ABOVE TO CUSTOMERS?

A. I agree that AMI can *potentially* offer all of these benefits. However, it is not possible to say that customers *will* benefit, or how those benefits might be distributed to different customers because the Company's application lacks crucial details in the area of future rate options, how they will be implemented, how customer rates will be impacted (e.g., customer charges for advanced rate designs) and the tools that may be made available to customers to assist them in modifying their energy usage patterns so as to benefit from the new rates. NCSEA Witness Murray discusses tools that allow customers to better understand their energy use patterns and assist them in managing their energy costs in greater detail.

Q. HAS THE COMPANY CONDUCTED A COST-BENEFIT ANALYSIS OF ITS AMI DEPLOYMENT PLANS?

A. The Company filed a Smart Grid Technology Plan ("SGTP") update with the Commission on October 2, 2017, which contains a cost-benefit analysis for AMI deployment.[48] It is not clear to me whether this filing represents a final cost-benefit analysis that will be presented for internal approval, but nevertheless it appears to represent the Company's most up to date analysis.

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[47] See for example, the Direct Testimony of Retha Hunsicker. p. 10, lines 13-20 discussing new programs and the ability to offer new rate options.
[48] 2017 Smart Grid Technology Plans of Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC. October 2, 2017. NCUC Docket No. E-100, Sub 147.

Q. DOES THE COMPANY'S COST-BENEFIT ANALYSIS ADDRESS THE CONCERNS YOU RAISED ABOUT THE BENEFITS OF AMI DEPLOYMENT FOR CUSTOMERS?

A. No. The analysis and accompanying material do not contain any additional details on the rate options the Company is considering or how they will be developed and deployed. The benefits assessment focuses on elements such as reduced meter reading expenses, storm response efficiency and cost savings, and other operational cost reductions. Moreover, the majority of benefits, $258.7 million of the total projected benefits of $452.1 million over 20 years, accrue in the category of "non-technical line loss reduction", which is categorized as increased utility revenue.[49] This category is explained as referring to increased revenue from earlier identification of things like malfunctioning meters, tampering, and theft. It was projected based on a 2008 study from the Electric Power Research Institute ("EPRI") rather than DEP-specific data on actual costs in this category, or with AMI deployment in Duke Energy Carolina's territory.[50] If not for this category, or if the projection was significantly reduced, the analysis would show a net cost to customers.

Ultimately, I do not dispute that operational or capital cost savings, and reduced revenue losses, would benefit customers as a whole. However, given the significance of the line loss reduction benefit projection in relation to overall projected benefits, this element specifically requires greater scrutiny. Furthermore, the Company has failed to describe new rate options, and has not

[49] Ibid. Appendix C, Exhibit C.
[50] Ibid. Appendix C, Exhibit F, p. 4.

evaluated how they would affect customers or how they would be designed and implemented in order to support system cost savings. The Company's testimony in this proceeding indicates that this is a significant factor in pursuing AMI deployment, yet its analysis entirely excludes it.

Q. HOW MIGHT AMI DEPLOYMENT AFFECT THE RATES CHARGED TO CUSTOMERS?

A. It is impossible to know exactly with the present information. However, given that AMI meters are more expensive than traditional meters and the fact that existing meters would be removed before the end of their service life, it is reasonable to expect that it would create upward pressure on customer costs and consequently customer charges. It is not clear how much operational savings on customer-related functions (e.g., meter reading) would offset this upward pressure. It is also not clear what opportunities would exist for customers to achieve bill savings that work to offset any incremental effect on customer charges that do exist because there is no information on what new rate options will look like. This is highly troubling at a time when the Company is already seeking extreme increases in customer charges, especially for the residential class. It is easy to see a scenario where residential customers lack the ability to achieve bill savings under new rate designs, but still shoulder the bulk of the burden of paying for AMI deployment.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION WITH RESPECT TO THE COMPANY'S AMI DEPLOYMENT PLANS?

A. I recommend that the Commission undertake a thorough review of DEP's AMI deployment plans from the perspective of how they will affect customer rates,

both generally and from the perspective of individual customer classes. This analysis should be incorporated into the overarching grid modernization proceeding recommended by NCSEA Witness Golin and should incorporate the recommendations of NCSEA Witness Murray.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission:

1. Hold customer charges at their present levels, or in the alternative allow them to increase by no more than the overall class revenue percentage increase.
2. Seek to establish a consistent methodology for determining customer-related costs based on cost causation principles in order to promote fairness and consistency between utilities.
3. Find that all coal ash remediation costs are property classified as energy-related costs and direct the Company to reflect this classification in its cost of service study and class revenue requirements.
4. Undertake a review of the Company's AMI deployment plan as part of a broader grid modernization proceeding, with a strategic focus on ensuring that AMI deployment and related activities or investments consistently support customer opportunities for bill savings and system benefits.

Q. DOES THIS CONCLUDE YOU TESTIMONY?

A. Yes.

JUSTIN R. BARNES

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EDUCATION

Michigan Technological University Houghton, Michigan
Master of Science, Environmental Policy, August 2006
Graduate-level work in Energy Policy.

University of Oklahoma Norman, Oklahoma
Bachelor of Science, Geography, December 2003
Area of concentration in Physical Geography.

RELEVANT EXPERIENCE

Director of Research, July 2015 – present
Senior Analyst & Research Manager, March 2013 – July 2015
EQ Research, LLC and Keyes, Fox & Wiedman, LLP Cary, North Carolina

- Oversee state legislative, regulatory policy, and general rate case tracking service that covers policies such as net metering, interconnection standards, rate design, renewables portfolio standards, state energy planning, state and utility incentives, tax incentives, and permitting.
- Responsible for service design, formulating improvements based on client needs, and ultimate delivery of reports to clients. Expanded service to cover energy storage.
- Oversee and perform policy research and quantitative or qualitative analysis to fulfill client requests, and for internal and published reports, focused primarily on state solar market drivers such as net metering, rate design, incentives, and renewable portfolio standards.
- Provide expert witness testimony on issues related to overall DG policy, rate design, cost of service, and DG costs and benefits.

Senior Policy Analyst, January 2012 – May 2013;
Policy Analyst, September 2007 – December 2011
North Carolina Solar Center, N.C. State University Raleigh, North Carolina

- Responsible for researching and maintaining information for the Database of State Incentives for Renewables and Efficiency (DSIRE), the most comprehensive public source of renewables and energy efficiency incentives and policy data in the United States.
- Managed state-level regulatory tracking for private wind and solar companies.
- Coordinated the organization's participation in the SunShot Solar Outreach Partnership, a U.S. Department of Energy project to provide outreach and technical assistance for local governments to develop and transform local solar markets.
- Developed and presented educational workshops, reports, administered grant contracts and associated deliverables, provided support for the SunShot Initiative, and worked with diverse group of project partners on this effort.
- Responsible for maintaining the renewable portfolio standard dataset for the National Renewable Energy Laboratory for use in its electricity modeling and forecasting analysis.
- Authored the *DSIRE RPS Data Updates*, a monthly newsletter providing up-to-date data and historic compliance information on state RPS policies.
- Responded to information requests and provided technical assistance to the general public, government officials, media, and the energy industry on a wide range of subjects, including federal tax incentives, state property taxes, net metering, state renewable portfolios standard policies, and renewable energy credits.

- Extensive experience researching, understanding, and disseminating information on complex issues associated with utility regulation, policy best practices, and emerging issues.

SELECTED ARTICLES and PUBLICATIONS

- EQ Research and Synapse Energy Economics for Delaware Riverkeeper Network. *Envisioning Pennsylvania's Energy Future*. 2016.
- Barnes, J., R. Haynes. *The Great Guessing Game: How Much Net Metering Capacity is Left?*. September 2015. Published by EQ Research, LLC.
- Barnes, J., Kapla, K. *Solar Power Purchase Agreements (PPAs): A Toolkit for Local Governments*. July 2015. For the Interstate Renewable Energy Council, Inc. under the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *2013 RPS Legislation: Gauging the Impacts*. December 2013. Article in Solar Today.
- Barnes, J., C. Laurent, J. Uppal, C. Barnes, A. Heinemann. *Property Taxes and Solar PV: Policy, Practices, and Issues*. July 2013. For the U.S. DOE SunShot Solar Outreach Partnership.
- Kooles, K, J. Barnes. *Austin, Texas: What is the Value of Solar; Solar in Small Communities: Gaston County, North Carolina*; and *Solar in Small Communities: Columbia, Missouri*. 2013. Case Studies for the U.S. DOE SunShot Solar Outreach Partnership.
- Barnes, J., C. Barnes. *The Report of My Death Was An Exaggeration: Renewables Portfolio Standards Live On*. 2013. For Keyes, Fox & Wiedman.
- Barnes, J. *Why Tradable SRECs are Ruining Distributed Solar*. 2012. Guest Post in Greentech Media Solar.
- Barnes, J., multiple co-authors. *State Solar Incentives and Policy Trends*. Annually for five years, 2008-2012. For the Interstate Renewable Energy Council, Inc.
- Barnes, J. *Solar for Everyone?* 2012. Article in Solar Power World On-line.
- Barnes, J., L. Varnado. *Why Bother? Capturing the Value of Net Metering in Competitive Choice Markets*. 2011. American Solar Energy Society Conference Proceedings.
- Barnes, J. *SREC Markets: The Murky Side of Solar*. 2011. Article in State and Local Energy Report.
- Barnes, J., L. Varnado. *The Intersection of Net Metering and Retail Choice: an overview of policy, practice, and issues*. 2010. For the Interstate Renewable Energy Council, Inc.

TESTIMONY

- Public Utility Commission of Texas, Control No. 46831. June 2017
- Utah Public Service Commission. Docket No. 14-035-114. June 2017.
- Colorado Public Utilities Commission, Proceeding No. 16A-0055E. May 2016.
- Public Utility Commission of Texas, Control No. 44941. December 2015.
- Oklahoma Corporation Commission, Cause No. PUD 201500271. November 2015.
- South Carolina Public Service Commission, Docket No. 2015-54-E. May 2015.
- South Carolina Public Service Commission, Docket No. 2015-53-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2015-55-E. April 2015.
- South Carolina Public Service Commission, Docket No. 2014-246-E. December 2014.

AWARDS, HONORS & AFFILIATIONS

- Solar Power World Magazine, Editorial Advisory Board Member (October 2011 – March 2013)
- Michigan Tech Finalist for the Midwest Association of Graduate Schools Distinguished Master's Thesis Awards (2007)
- Sustainable Futures Institute Graduate Scholar Michigan Tech University (2005-2006)

Table 1: National Residential Fixed Charge Comparison (Current Rates)[1]

State	Utility	Existing Fixed Charge	Rank
Wyoming	Montana-Dakota Utilities[2]	$25.00	1
New York	Central Hudson Gas & Electric [3]	$24.00	2
Mississippi	Mississippi Power[4]	$23.71	3
New York	RG&E[5]	$21.38	4
Wisconsin	Wisconsin Public Service[6]	$21.00	5
Hawaii	Hawaii Electric Light (HELCO)[7]	$20.50	6
New York	Orange & Rockland Utilities[8]	$20.00	7
Oklahoma	PSO[9]	$20.00	8
Wyoming	Rocky Mountain Power[10]	$20.00	9
Florida	Gulf Power[11]	$19.76	10
North Carolina	**Duke Energy Progress (PROPOSED)**	**$19.50**	**11[a]**
Connecticut	Eversource[12]	$19.25	11
Wisconsin	MGE[13]	$19.00	12
Hawaii	Maui Electric (MECO)[14]	$18.00	13
Hawaii	Hawaiian Electric (HECO)[15]	$17.00	16
Indiana	IP&L[16]	$17.00	14
New York	National Grid[17]	$17.00	15
Illinois	Ameren Illinois[18]	$16.97	17
Florida	Tampa Electric[19]	$16.62	18
Colorado	Black Hills Energy[20]	$16.50	19
Wisconsin	We Energies[21]	$15.99	20
New York	Con Edison[22]	$15.76	21
Wyoming	Black Hills Power[23]	$15.50	22
Illinois	Commonwealth Edison[24]	$15.27	23
Nevada	Sierra Pacific Power Company[25]	$15.25	24
New Hampshire	Unitil[26]	$15.24	25
New York	NYSEG[27]	$15.11	26
District of Columbia	Pepco[28]	$15.09	27
Arizona	UniSource Energy Services[29]	$15.00	28
Michigan	Upper Peninsula Power Company[30]	$15.00	29
Wisconsin	Alliant Energy[31]	$15.00	30
Alabama	Alabama Power[32]	$14.50	31
Kansas	Westar Energy[33]	$14.50	32
New Hampshire	Liberty Utilities[34]	$14.50	33
North Dakota	Xcel Energy[35]	$14.50	34
Pennsylvania	PPL Electric Utilities[36]	$14.09	35
Florida	Florida Public Utilities[37]	$14.00	36
Indiana	NIPSCO[38]	$14.00	37
Kansas	Empire District Electric[39]	$14.00	38
Kansas	KCP&L[40]	$14.00	39
Wisconsin	Xcel Energy[41]	$14.00	40
North Dakota	Montana-Dakota Utilities[42]	$13.98	41
Alaska	Alaska Power Company[43]	$13.85	42
Vermont	Green Mountain Power[44]	$13.16	43

[a] Rank numbering continues so as to exclude Duke Energy Progress, resulting in consecutive ranks of 11.

Arizona	Tucson Electric Power[45]	$13.00	47
Missouri	Empire District Electric[46]	$13.00	44
Oklahoma	OG&E[47]	$13.00	45
Wyoming	Black Hills Energy[48]	$13.00	46
Nevada	Nevada Power Company[49]	$12.75	48
New Hampshire	Eversource[50]	$12.64	49
Tennessee	Kingsport Power (AEP AppCo)[51]	$12.63	50
Missouri	KCP&L[52]	$12.62	51
Oklahoma	Empire District Electric[53]	$12.50	52
Kentucky	Kentucky Utilities[54]	$12.25	53
Kentucky	LG&E[55]	$12.25	54
Michigan	Wisconsin Public Service[56]	$12.00	55
Virginia	Kentucky Utilities[57]	$12.00	56
Iowa	Alliant Energy[58]	$11.95	57
North Carolina	Duke Energy Carolinas[59]	$11.80	58
Delaware	Delmarva Power[60]	$11.70	59
Pennsylvania	Citizens' Electric Company[61]	$11.50	60
Pennsylvania	Met-Ed[62]	$11.25	61
Pennsylvania	Penelec[63]	$11.25	62
North Carolina	**Duke Energy Progress[64] (CURRENT)**	**$11.13**	**63**
Arkansas	Empire District Electric[65]	$11.04	64
Indiana	Vectren Indiana[66]	$11.00	65
Kentucky	Kentucky Power[67]	$11.00	66
Pennsylvania	Penn Power[68]	$11.00	67
Wisconsin	Northwestern Wisconsin Electric[69]	$11.00	68
North Carolina	Dominion North Carolina Power[70]	$10.96	69
Pennsylvania	Wellsboro Electric Company[71]	$10.95	70
Maine	Central Maine Power[72]	$10.68	71
Oregon	Portland General Electric[73]	$10.50	72
Missouri	KCP&L Greater Missouri Operations[74]	$10.43	73
Arizona	Arizona Public Service[75]	$10.00	94
California	SCE[76]	$10.00	78
California	PG&E[77]	$10.00	79
California	SDG&E[78]	$10.00	80
Georgia	Georgia Power Company[79]	$10.00	75
South Carolina	South Carolina Electric & Gas[80]	$10.00	76
Texas	Sharyland Utilities[81]	$10.00	74
Texas	Xcel Energy[82]	$10.00	77
Arkansas	Oklahoma Gas & Electric[83]	$9.75	81
Minnesota	Otter Tail Power Company[84]	$9.75	82
Connecticut	United Illuminating[85]	$9.67	83
Oregon	Pacific Power[86]	$9.50	84
Indiana	Duke Energy Indiana[87]	$9.40	85
South Dakota	Black Hills Power[88]	$9.25	86
Alaska	Alaska Electric Light & Power[89]	$9.22	87
South Carolina	Duke Energy Progress[90]	$9.06	88
Missouri	Ameren Missouri[91]	$9.00	89
Wisconsin	Superior Water Light & Power[92]	$9.00	90
Illinois	MidAmerican Energy[93]	$8.97	91
Florida	Duke Energy Florida[94]	$8.76	92

Michigan	Xcel Energy[95]	$8.75	93
Iowa	MidAmerican Energy[96]	$8.50	95
New Mexico	Xcel Energy (SPS)[97]	$8.50	96
Washington	Avista Utilities[98]	$8.50	97
Pennsylvania	PECO[99]	$8.45	98
Arkansas	Entergy Arkansas[100]	$8.40	99
Ohio	Ohio Power Company[101]	$8.40	100
Virginia	Appalachian Power Company[102]	$8.35	101
South Carolina	Duke Energy Carolinas[103]	$8.29	102
South Dakota	Xcel Energy[104]	$8.25	103
Texas	AEP Texas North[105]	$8.18	104
Maryland	Delmarva Power[106]	$8.17	105
Minnesota	Minnesota Power[107]	$8.00	106
Minnesota	Xcel Energy[108]	$8.00	107
North Dakota	Otter Tail Power Company[109]	$8.00	111
Oregon	Idaho Power Company[110]	$8.00	108
South Dakota	MidAmerican Energy[111]	$8.00	109
South Dakota	Otter Tail Power Company[112]	$8.00	110
Texas	SWEPCO[113]	$8.00	112
Utah	Rocky Mountain Power[114]	$8.00	114
West Virginia	Appalachian Power Company[115]	$8.00	113
Maryland	BGE[116]	$7.90	115
Florida	Florida Power & Light[117]	$7.87	116
Arkansas	SWEPCO[118]	$7.75	117
Washington	Pacific Power[119]	$7.75	118
Maryland	Pepco[120]	$7.60	119
Maine	Emera Maine[121]	$7.54	120
Michigan	DTE[122]	$7.50	121
South Dakota	Montana-Dakota Utilities[123]	$7.50	122
Washington	Puget Sound Energy[124]	$7.49	123
Pennsylvania	West Penn Power[125]	$7.44	124
Indiana	Indiana Michigan Power[126]	$7.30	125
Michigan	Indiana Michigan Power[127]	$7.25	126
California	Pacific Power[128]	$7.20	127
Louisiana	Entergy Louisiana[129]	$7.04	128
Massachusetts	Unitil[130]	$7.00	129
Michigan	Consumers Energy[131]	$7.00	130
New Mexico	El Paso Electric[132]	$7.00	131
New Mexico	PNM[133]	$7.00	132
Texas	Entergy Texas[134]	$7.00	133
Virginia	Dominion Virginia[135]	$7.00	134
Texas	El Paso Electric[136]	$6.90	135
Mississippi	Entergy Mississippi[137]	$6.75	136
Texas	AEP Texas Central[138]	$6.74	137
California	Liberty Utilities[139]	$6.56	138
Massachusetts	Eversource Eastern[140]	$6.43	139
California	Bear Valley Electric Service[141]	$6.39	140
Massachusetts	Eversource Western[142]	$6.00	141
Ohio	Duke Energy Ohio[143]	$6.00	142
South Dakota	NorthWestern Energy[144]	$6.00	143

Idaho	Avista Utilities[145]	$5.75	144
Massachusetts	National Grid[146]	$5.50	145
Louisiana	SWEPCO[147]	$5.49	146
Montana	Montana-Dakota Utilities[148]	$5.47	147
Texas	Centerpoint Energy[149]	$5.47	148
Colorado	Xcel Energy[150]	$5.39	149
Idaho	Rocky Mountain Power[151]	$5.00	150
Idaho	Idaho Power Company[152]	$5.00	151
Maryland	Potomac Edison[153]	$5.00	152
Michigan	Alpena Power Company[154]	$5.00	153
New Jersey	Atlantic City Electric[155]	$5.00	156
Rhode Island	National Grid[156]	$5.00	155
West Virginia	First Energy Utilities[157]	$5.00	154
New Jersey	Rockland Electric[158]	$4.54	157
Kentucky	Duke Energy Kentucky[159]	$4.50	158
Louisiana	Entergy Louisiana (Legacy EGSL)[160]	$4.46	159
Ohio	Dayton Power & Light[161]	$4.25	160
Montana	NorthWestern Energy[162]	$4.10	161
Ohio	First Energy Utilities[163]	$4.00	162
Texas	Oncor[164]	$3.06	163
New Jersey	JCP&L[165]	$2.98	164
New Jersey	PSEG[166]	$2.27	165
	Average	**$10.59**	
	Average (Excluding DEP NC)	**$10.59**	

Table 2: Recent Fixed Charge Approvals[167]

State	Utility	Existing Fixed Charge	Approved Fixed Charge	$ Increase Approved	Approved % Increase
Arizona	Tucson Electric Power[168]	$10.00	$13.00	$3.00	30.0%
Arizona	UniSource Energy[169]	$10.00	$15.00	$5.00	50.0%
Arizona	Arizona Public Service[170]	$8.66	$10.00	$1.34	15.5%
Arkansas	Entergy Arkansas[171]	$6.96	$8.40	$1.44	20.7%
Arkansas	Oklahoma Gas & Electric[172]	$7.94	$9.75	$1.81	22.8%
California	Liberty Utilities[173]	$7.10	$6.56	-$0.54	-7.6%
California	SDG&E[174]	$10.00	$10.00	$0.00	0.0%
Colorado	Black Hills Energy[175]	$16.50	$16.50	$0.00	0.0%
Colorado	Xcel Energy[176]	$6.75	$5.39	-$1.36	-20.1%
Connecticut	Eversource[177]	$16.00	$19.25	$3.25	20.3%
Connecticut	United Illuminating[178]	$17.25	$9.67	-$7.58	-43.9%
Delaware	Delmarva Power[179]	$11.70	$11.70	$0.00	0.0%
D.C.	Pepco[180]	$13.00	$15.09	$2.09	16.1%
Florida	Florida Power & Light[181]	$7.87	$7.87	$0.00	0.0%
Florida	Gulf Power[182]	$18.85	$19.76	$0.65	3.4%
Idaho	Avista Utilities[183]	$5.25	$5.75	$0.50	9.5%
Idaho	Avista Utilities[184]	$5.25	$5.25	$0.00	0.0%
Indiana	IP&L[185]	$11.00	$17.00	$6.00	54.5%
Indiana	NIPSCO[186]	$11.00	$14.00	$3.00	27.3%
Kansas	KCP&L[187]	$10.71	$14.00	$3.29	30.7%
Kansas	Westar Energy[188]	$12.00	$14.50	$2.50	20.8%
Kentucky	Kentucky Power[189]	$8.00	$11.00	$3.00	37.5%
Kentucky	Kentucky Utilities[190]	$10.75	$12.25	$1.50	14.0%
Kentucky	Kentucky Utilities[191]	$10.75	$10.75	$0.00	0.0%
Kentucky	LG&E[192]	$10.75	$10.75	$0.00	0.0%
Maine	Emera Maine[193]	$5.82	$7.54	$1.72	29.6%
Maryland	BGE[194]	$7.50	$7.90	$0.40	5.3%
Maryland	BGE[195]	$7.50	$7.50	$0.00	0.0%
Maryland	Delmarva Power[196]	$7.94	$8.17	$0.23	2.9%
Maryland	Pepco[197]	$7.39	$7.60	$0.21	2.8%
Massachusetts	National Grid[198]	$4.00	$5.50	$1.50	37.5%
Massachusetts	Unitil[199]	$7.00	$7.00	$0.00	0.0%
Michigan	Consumers Energy[200]	$7.00	$7.00	$0.00	0.0%
Michigan	Consumers Energy[201]	$7.00	$7.00	$0.00	0.0%
Michigan	DTE[202]	$6.00	$7.50	$1.50	25.0%
Michigan	DTE[203]	$6.00	$6.00	$0.00	0.0%
Michigan	Indiana Michigan Power[204]	$7.25	$7.25	$0.00	0.0%
Michigan	Upper Peninsula Power[205]	$12.00	$15.00	$3.00	25.0%
Michigan	Wisconsin Public Service[206]	$9.00	$12.00	$3.00	33.3%
Michigan	Xcel Energy[207]	$8.65	$8.75	$0.10	1.2%
Minnesota	Otter Tail Power[208]	$8.50	$9.75	$1.25	14.7%
Minnesota	Xcel Energy[209]	$8.00	$8.00	$0.00	0.0%
Mississippi	Mississippi Power[210]	$23.71	$23.71	$0.00	0.0%
Missouri	Ameren Missouri[211]	$8.00	$9.00	$1.00	12.5%

Missouri	Ameren Missouri[212]	$8.00	$8.00	$0.00	0.0%
Missouri	Empire District Electric[213]	$12.52	$13.00	$0.48	3.8%
Missouri	Empire District Electric[214]	$12.52	$12.52	$0.00	0.0%
Missouri	KCP&L[215]	$11.88	$12.62	$0.74	6.2%
Missouri	KCP&L[216]	$9.00	$11.88	$2.88	32.0%
Missouri	KCP&L Greater Missouri[217]	$9.54	$10.43	$0.89	9.3%
Montana	Montana-Dakota Utilities[218]	$5.47	$5.47	$0.00	0.0%
Nevada	Sierra Pacific Power[219]	$15.25	$15.25	$0.00	0.0%
New Hampshire	Liberty Utilities[220]	$11.79	$14.50	$2.71	23.0%
New Hampshire	Unitil[221]	$10.27	$15.24	$4.97	48.4%
New Jersey	Atlantic City Electric[222]	$4.00	$4.44	$0.44	11.0%
New Jersey	Atlantic City Electric[223]	$4.44	$5.00	$0.56	12.6%
New Jersey	JCP&L[224]	$1.92	$2.98	$1.06	55.2%
New Jersey	Rockland Electric[225]	$4.44	$4.54	$0.10	2.3%
New Mexico	El Paso Electric[226]	$7.00	$7.00	$0.00	0.0%
New Mexico	PNM[227]	$5.00	$7.00	$2.00	40.0%
New Mexico	Xcel Energy[228]	$7.90	$8.50	$0.60	7.6%
New York	Central Hudson[229]	$24.00	$24.00	$0.00	0.0%
New York	Con Edison[230]	$15.76	$15.76	$0.00	0.0%
New York	Con Edison[231]	$15.76	$15.76	$0.00	0.0%
New York	NYSEG[232]	$15.11	$15.11	$0.00	0.0%
New York	Orange & Rockland[233]	$20.00	$20.00	$0.00	0.0%
New York	RG&E[234]	$21.38	$21.38	$0.00	0.0%
North Carolina	Dominion North Carolina[235]	$10.96	$10.96	$0.00	0.0%
North Dakota	Montana-Dakota Utilities[236]	$10.65	$13.98	$3.33	31.3%
Oklahoma	OG&E[237]	$13.00	$13.00	$0.00	0.0%
Oklahoma	PSO[238]	$20.00	$20.00	$0.00	0.0%
Oregon	Portland General Electric[239]	$10.00	$10.50	$0.50	5.0%
Pennsylvania	Citizens' Electric[240]	$8.00	$11.50	$3.50	43.8%
Pennsylvania	Met-Ed[241]	$10.25	$11.25	$1.00	9.8%
Pennsylvania	Met-Ed[242]	$8.11	$10.25	$2.14	26.4%
Pennsylvania	PECO[243]	$7.12	$8.45	$1.33	18.7%
Pennsylvania	Penelec[244]	$9.99	$11.25	$1.26	12.6%
Pennsylvania	Penelec[245]	$7.98	$9.99	$2.01	25.2%
Pennsylvania	Penn Power[246]	$10.85	$11.00	$0.15	1.4%
Pennsylvania	Penn Power[247]	$8.89	$10.85	$1.96	22.0%
Pennsylvania	PPL Electric Utilities[248]	$14.09	$14.09	$0.00	0.0%
Pennsylvania	Wellsboro Electric[249]	$9.75	$10.95	$1.20	12.3%
Pennsylvania	West Penn Power[250]	$5.81	$7.44	$1.63	28.1%
Pennsylvania	West Penn Power[251]	$5.00	$5.81	$0.81	16.2%
South Carolina	Duke Energy Progress[252]	$6.50	$9.06	$2.56	39.4%
South Dakota	MidAmerican Energy[253]	$7.00	$8.00	$1.00	14.3%
South Dakota	Montana-Dakota Utilities[254]	$6.00	$7.50	$1.50	25.0%
South Dakota	NorthWestern Energy[255]	$5.00	$6.00	$1.00	20.0%
South Dakota	Xcel Energy[256]	$8.25	$8.25	$0.00	0.0%
Tennessee	Kingsport Power[257]	$7.30	$12.63	$5.33	73.0%
Texas	El Paso Electric[258]	$5.00	$6.90	$1.90	38.0%
Texas	Xcel Energy[259]	$9.50	$10.00	$0.50	5.3%
Texas	Xcel Energy[260]	$7.60	$9.50	$1.90	25.0%
Virginia	Kentucky Utilities[261]	$12.00	$12.00	$0.00	0.0%

Washington	Avista Utilities[262]	$8.50	$8.50	$0.00	0.0%
Washington	Avista Utilities[263]	$8.50	$8.50	$0.00	0.0%
Wisconsin	Alliant Energy[264]	$7.67	$15.00	$7.33	95.6%
Wisconsin	MGE[265]	$19.00	$19.00	$0.00	0.0%
Wisconsin	NW Wisconsin Electric[266]	$7.50	$11.00	$3.50	46.7%
Wisconsin	SWL&P[267]	$7.00	$9.00	$2.00	28.6%
Wisconsin	Wisconsin Public Service[268]	$19.00	$21.00	$2.00	10.5%
Wisconsin	Xcel Energy[269]	$14.00	$14.00	$0.00	0.0%
Wisconsin	Xcel Energy[270]	$8.00	$14.00	$6.00	75.0%
Wyoming	Montana-Dakota Utilities[271]	$25.00	$25.00	$0.00	0.0%
Wyoming	Rocky Mountain Power[272]	$20.00	$20.00	$0.00	0.0%
AVERAGES		**$10.16**	**$11.27**	**$1.11**	**14.09%**

[1] Table 1 and Table 2 characterize the minimum bills in California, Hawaii, and Utah as fixed charges, though they are not strictly speaking fixed charges. This affects the rankings and averages to a small degree, inflating the average fixed charge and placing Duke Energy utilities slightly lower on the ranking scale than they would otherwise be because minimum bill for HELCO in Hawaii is substantially higher than the fixed monthly customer charge.

[2] WY PSC. Docket No. 14409. Order No. 23958. Appendix A, p. 11. April 6, 2017. Charge is stated as $0.822/day, translating to a monthly charge of $25.00/month.

[3] NY PSC. Case No. 14-E-0318. Order Approving Rate Plan. p. 57. June 17, 2016. Order rejected settlement providing for an increase in the fixed charge, retaining it at $24.00/month. See current SC-1 rate, available at: https://www.cenhud.com/rates/index

[4] MS PSC. Docket No. 2015-UN-80. PSC Order. December 3, 2015. Base charge of $0.78 per day, translating to a monthly charge of $23.79. See current Rate R-55, available at: http://www.mississippipower.com/my-home/my-bill/pricing-and-rates

[5] NY PSC. Case No. 15-E-0285. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current RGE Rate SC-1, available at: https://www.rge.com/SuppliersAndPartners/pricingandtariffs/tariffratesummaries/psc19.html

[6] WI PSC. Docket No. 6690-UR-124. Final Decision. p. 63. December 17, 2015.

[7] Hawaii Electric Light (HELCO). Schedule R, available at: https://www.hawaiianelectric.com/my-account/rates-and-regulations/hawaii-electric-light-rates

[8] NY PSC. Case No. 14-E-0493. Order Establishing Rate Plan. Appendix 18, Schedule 1. October 16, 2015.

[9] OK Corporation Commission. Cause No. PUD 201500208. Order No. 657877. November 10, 2016. See current Schedule RS, available at: https://www.psoklahoma.com/account/bills/rates/

[10] WY PSC. Docket No. 14076. Order No. 23208. December 30, 2015. See current Schedule 2 available at: https://www.rockymountainpower.net/about/rar/wri.html

[11] FL PSC. Docket No. 160186-EI. Order No. PSC-17-0178-S-EI. p. 3. June 16, 2017. Order retains the existing residential rate structure. See Schedule RS, stating the charge as $0.65/day, translating to a monthly charge of $19.76, available at: https://www.gulfpower.com/residential/savings-and-energy/rates-and-billing/rates-rules-and-regulations

[12] CT PURA. Docket No. 14-05-06. Decision dated December 17, 2014. p. 190.

[13] WI PSC. Docket No. 3270-UR-121. Final Decision. Appendix B, p. 2. December 15, 2016.

[14] Maui Electric (MECO). Maui Schedule R, available at: https://www.hawaiianelectric.com/my-account/rates-and-regulations/maui-electric-rates---maui

[15] Hawaii Electric (HECO). Schedule R, available at: https://www.hawaiianelectric.com/my-account/rates-and-regulations/hawaiian-electric-rates

[16] IN URC. Cause No. 44576. Final Order. p. 72. March 16, 2016.

[17] National Grid. Schedule SC-1, available at: https://www9.nationalgridus.com/niagaramohawk/home/rates/4_standard.asp

[18] Ameren Illinois. Schedule DS-1, Historic Delivery Charges Informational Sheets. Calculated as the sum of the customer charge, meter charge, and uncollectables monthly fee. Available at: https://www.ameren.com/illinois/rates/historical-map-p
[19] Tampa Electric Company. Schedule RS (Sheet No. 6.030), available at: http://www.tampaelectric.com/company/ourpowersystem/tariff/
[20] CO PUC. Docket No. 16AL-0326E. Decision No. C16-1140. p. 36. December 19, 2016. See current schedule RS-1, available at: https://www.blackhillsenergy.com/node/19559
[21] We Energies. Schedule Rg-1. Stated as a charge of $0.52602/day, translating to a monthly charge of $15.99. Available at: http://www.we-energies.com/residential/rates_policies/index.htm
[22] NY PSC. Case No. 16-E-0060. Order Approving Electric Rate Plan. January 25, 2017. Order adopted a joint party proposal maintaining the existing rate. See Schedule SC-1, available at: https://www2.dps.ny.gov/ETS/jobs/display/download/6090846.pdf
[23] Black Hills Power Wyoming. Schedule R. Available at: https://www.blackhillsenergy.com/rates. Note that a different rate applies for Black Hills Energy (dba Cheyenne Light & Power), also included in Table 1.
[24] Commonwealth Edison. Rate DSPP, Delivery Service Charges. Available at: https://www.comed.com/MyAccount/MyBillUsage/Pages/CurrentRatesTariffs.aspx. Stated rate is the sum of customer, metering and uncollectables factor charges.
[25] PUCN. Docket No. 16-06006. Order Granting in Part and Denying Part General Rate Application by Sierra Pacific Power. December 22, 2016. See tariff compliance filing dated December 30, 2016 (Sheet 63G) showing no change in the residential customer charge, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-6/17802.pdf
[26] NH PUC. Docket No. DE 16-384. Order No. 26,007. p. 10-11. April 20, 2017. Order adopts a customer charge of $15/month, with a step adjustment effective May 1, 2017 to the current $15.24/month rate. See Schedule D, available at: http://unitil.com/energy-for-residents/electric-information/tariffs
[27] NY PSC. Case No. 15-E-0283. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current NYSEG Rate SC-1, available at: http://www.nyseg.com/SuppliersAndPartners/pricingandtariffs/electricitytariffs/PSC120TableOfContents.html
[28] DC PSC. Docket No. FC 1139. Order No. 18846. p. 145. July 24, 2017.
[29] AZ Corporation Commission. Docket No. E-4204A-15-0142. Decision No. 75697. p. 66. August 18, 2016.
[30] MI PSC. Docket No. U-17895. Final Order. p. 55. September 8, 2016
[31] WI PSC. Docket No. 660-UR-120. Final Decision. p. 7. December 22, 2016.
[32] Alabama Power. Rate FD (Family Dwelling). Available at: https://www.alabamapower.com/residential/residential-pricing-and-rates/standard-family-dwelling-rate.html
[33] KS Corporation Commission. Docket No. 15-WSEE-115-RTS. Order Approving Stipulation .p. 22. September 24, 2015. Order adopted the settlement proposing a $14.50/month customer charge.
[34] NH PUC. Docket No. DE 16-383. Order No. 26,005. p. 8. April 12, 2017.
[35] Xcel Energy North Dakota. Residential Service, Section 5, Sheet 1. Available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/ND/Ne_Section_05.pdf
[36] PA PUC. Docket No. R-2015-2469275. Opinion and Order. p. 8. November 19, 2015.
[37] Florida Public Utilities. Schedule RS, available at: http://www.fpuc.com/electric/rates-tariffs/
[38] IN URC. Cause No. 44688. Final Order. p. 68. July 18, 2016.
[39] Empire District Electric Kansas. Schedule RG (Residential General Service). Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/KS
[40] KS Corporation Commission. Docket No, 15-KCPE-116-RTS. Final Order. Attachment B, p. 4. September 10, 2015. Order adopted the settlement specifying the $14/month customer charge.
[41] WI PSC. Docket No. 4220-UR-122. Final Decision. Appendix B, p. 2. December 1, 2016.
[42] ND PSC. Case No. PU-16-666. Findings of Fact, Conclusions of Law and Order. p. 6. June 16, 2017. Charge is stated as $0.46/day, translating to a monthly charge of $13.98.
[43] Alaska Light and Power Company. Schedule A-1. Available at: https://www.aptalaska.com/regulatory/

[44] Green Mountain Power. Rate 1 Residential Service. Available at: http://www.greenmountainpower.com/rates/. Charge is stated as $0.433/day, translating to a monthly charge of $13.16.
[45] AZ Corporation Commission. Docket No. E-01933A-15-0322. p. 186. Decision No. 75795. February 24, 2017.
[46] MO PSC. Docket No. ER-2016-0023. Order Approving Stipulation and Agreement. p. 2. August 10, 2016.
[47] OK Corporation Commission. Cause No. PUD 201500273. Order No. 662059. p. 4. March 20, 2017. Order adopts the ALJ recommendation, retaining the existing customer charge at $13. See Schedule R-1, available at: https://oge.com/wps/wcm/connect/81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045/3.00+R-1.pdf?MOD=AJPERES&CACHEID=81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045
[48] Black Hills Energy (dba Cheyenne Light, Fuel & Power). Schedule R. Available at: https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/clfp_electricity.pdf
[49] Nevada Power Company. Schedule RS. Available at: https://www.nvenergy.com/publish/content/dam/nvenergy/brochures_arch/about-nvenergy/rates-regulatory/np_res_rate.pdf
[50] Eversource New Hampshire. Rate R. Available at: https://www.eversource.com/Content/nh/business/my-account/billing-rates/rates-tariffs/electric-tariffs-rules
[51] TN Regulatory Authority. Docket No. 1600001. Order Approving Stipulation. Attachment C, Schedule 1. October 19, 2016.
[52] MO PSC. Docket No. ER-2016-0285. Report and Order. p. 57. May 3, 2017.
[53] Empire District Electric Oklahoma. Schedule RG (Residential General Service). Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/OK
[54] KY PSC. Docket No. 2016-00370. Final Order. p. 19. May 22, 2017.
[55] KY PSC. Docket No. 2016-00371. Final Order. p. 22. May 22, 2017.
[56] MI PSC. Docket No. U-17669. Order Approving Settlement Agreement. Attachment A, p. 33. April 23, 2015.
[57] VA Corporation Commission. Docket No. PUC-2015-00063. Final Order. p. 5. February 2, 2016
[58] Alliant Energy Iowa. Electric Residential Usage Service. Available at: https://www.alliantenergy.com/CustomerService/AlliantEnergyService/RatesandTariffs/ElectricRatesIOWA. Current rate reflects an interim rate during the pending rate increase request in IUB Docket No RPU-2017-001. Prior to the interim rate, the rate was $10.50/month.
[59] Duke Energy Carolinas NC. Schedule RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/ncschedulers.pdf?la=en
[60] DE PSC. Docket No. 16-0649. Order No. 9048. Exhibit 2, p. 3. May 23, 2017.
[61] PA PUC. Docket No. R-2016-2531550. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule RS, available at: https://www.citizenselectric.com/TariffStart.asp
[62] PA PUC. Docket No. R-2016-2537349. Opinion and Order. p. 10. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
[63] PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
[64] Duke Energy Progress NC. Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-nc/r1ncscheduleresdep.pdf?la=en
[65] Empire District Electric Arkansas. Schedule RG. Available at: https://www.empiredistrict.com/CustomerService/Rates/Electric/AR
[66] Vectren Indiana. Rate RS. Available at: https://www.vectren.com/information/rates
[67] KY PSC. Docket No. 2014-00396. Final Order. p. 57. June 22, 2015.

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[68] PA PUC. Docket No. R-2016-2537355. Opinion and Order. p. 13. January 19, 2017. Order approved a party settlement resulting in the current rates. See Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0
[69] WI PSC. Docket No. 4280-ER-106. Final Decision. Appendix D, p. 1. June 20, 2017.
[70] NCUC. Docket No. E-22, Sub 532. Order Approving Rate Increase. p. 16. December 22, 2016. Adopted settlement provides for no customer charge increase, retaining the existing rate. See Schedule 1, available at: https://www.dominionenergy.com/library/domcom/pdfs/north-carolina-power/rates/shared/entire-filing.pdf?la=en
[71] PA PUC. Docket No. R-2016-2531551. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule No. 1, available at: https://wellsboroelectric.com/wp-content/uploads/2014/03/Distribution-Tariff-Supp-106-Apr-11-2017.pdf
[72] Central Maine Power. Rate A. Available at: http://www.cmpco.com/YourHome/pricing/pricingSchedules/default.html
[73] OR PUC. Docket No. UE 294. Order No. 15-356. p. 11. November 3, 2015.
[74] MO PSC. Docket No. ER-2016-0156. Order Approving Stipulation. September 28, 2016. Order adopted a settlement resulting in the current rates. See the non-unanimous settlement, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936033685
[75] AZ Corporation Commission. Docket No. E-01345A-16-0036. Decision No. 76364. September 19, 2017. Settlement Agreement. p. 17. Refers to the daily rate of $0.329 for Schedule R-XS applicable to customers with monthly use averaging 600 kWh or less. This replaces the former daily rate of $0.285 under Schedule E-12 as it existed prior to this proceeding.
[76] Southern California Edison. Schedule D. Available at: https://www.sce.com/NR/sc3/tm2/pdf/ce12-12.pdf. Listed rate refers to $0.329/day minimum bill, translating to $10/month.
[77] Pacific Gas and Electric. Schedule E-1. Available at: https://www.pge.com/tariffs/index.page. Listed rate refers to $0.32854/day minimum bill, translating to $10/month.
[78] San Diego Gas and Electric. Schedule DR. Available at: http://regarchive.sdge.com/tm2/ssi/inc_elec_rates_res.html. Listed rate refers to $0.329/day minimum bill, translating to $10/month.
[79] Georgia Power. Schedule R-22. Available at: https://georgiapower.com/docs/rates-schedules/residential-rates/2.10_R.pdf
[80] South Carolina Electric & Gas. Rate 8. Available at: https://www.sceg.com/paying-my-bill/rates
[81] Sharyland Utilities. Residential Service. Available at: http://1op2ep3s2jsaoeg8a36pkogmht.wpengine.netdna-cdn.com/wp-content/uploads/2017/04/03-23-17-sharyland-tariff-manual.pdf. Rate refers to SBC portion of territory excluding the McAllen division, calculated as the sum of the customer charge and metering charge.
[82] PUCT. Control No. 45524. Order Adopting Settlement. January 26, 2017. See current Residential Service schedule, available at: https://www.xcelenergy.com/company/rates_and_regulations/rates/texas_rates,_rights,_&_service_rules
[83] AR PSC. Docket No. 16-052-U. Order No. 8 Adopting Settlement. p. 9. May 18, 2017.
[84] MN PUC. Docket No. E-017/GR-15-1033. Findings of Fact, Conclusions and Order. p. 84. May 1, 2017.
[85] CT PURA. Docket No. 16-06-04. Final Decision. p. 96. December 14, 2016. Order sets "maximum" test year customer charge of $8.50, but requires an adjustment for the overall rate increase. See current Rate R, available at: https://uinet.custhelp.com/cgi-bin/uinet.cfg/php/enduser/std_adp.php?p_faqid=3418
[86] Pacific Power OR. Schedule 4. Available at: https://www.pacificpower.net/about/rr/ori.html
[87] Duke Energy Indiana. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-in/raters.pdf?la=en
[88] Black Hills Power SD. Rate Designation R. Available at: https://www.blackhillsenergy.com/sites/blackhillsenergy.com/files/bhp-sd-rates.pdf
[89] Alaska Electric Light & Power. Rate 10. Available at: https://www.aelp.com/Customer-Service/Rates-Billing/Current-Rates

[90] SC PSC. Docket No. 2016-227-E. Order Approving Settlement. December 21, 2016. See current rate Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/r1scscheduleres.pdf?la=en
[91] MO PSC. Docket No. ER-2016-0179. Decision Approving Settlement. p. 12. March 8, 2017. Decision approved a $1/month increase, reflected in current rate SC-1, available at: https://www.ameren.com/missouri/rates/electric-full-service-bundle
[92] WI PSC. Docket No. 5820-UR-114. Final Decision. Appendix B, page 2 of 6. August 10, 2017.
[93] MidAmerican Energy. Rate RS. Available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/ilelectric/il-elec.pdf. Calculated as the sum of the customer and metering charge.
[94] Duke Energy FL. Rate RS-1. Available at: https://www.duke-energy.com/home/billing/rates#tab-22bdf686-d7d1-46c4-92d5-053d18b95e49
[95] MI PSC. Docket U-17710. Order Approving Settlement Agreement. Attachment A, Residential Service Schedule MR-1. March 23, 2015.
[96] MidAmerican Energy IA. Rate RS. Available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/iaelectric/ia-elec.pdf
[97] NM PRC. Docket No. 16-00296-UT. Final Order Adopting Stipulation. August 10, 2016. See current Rate No. 1, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/NM/nm_sps_e_entire.pdf
[98] WA UTC. Docket No. UE-160228. p. 57. Final Order Rejecting Tariff Filing. December 15, 2016. Commission determined that the existing rates were just and reasonable and therefore retained them. See Rate Schedule No. 1, available at: https://myavista.com/about-us/our-rates-and-tariffs/washington-electric-resources
[99] PA PUC. Docket No. R-2015-2468981. Opinion and Order. p. 11. December 17, 2015.
[100] AR PSC. Docket No. 15-015-U. Final Order. February 23, 2016. Settlement resulted in the current rates under Schedule RS, available at: http://www.entergy-arkansas.com/your_home/tariffs.aspx
[101] Ohio Power Company. Schedule RS. Available at: https://www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx
[102] Appalachian Power Company. Schedule RS. Available at: https://appalachianpower.com/account/bills/rates/APCORatesTariffsVA.aspx
[103] Duke Energy Carolinas SC. Schedule RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-sc/scschedulers.pdf?la=en
[104] SD PUC Docket No. EL14-058. Order Adopting Settlement. June 16, 2015. See Settlement Exhibit PJS-2, Schedule 2-1 for prior and adopted rates, available at: http://puc.sd.gov/commission/dockets/electric/2014/EL14-058/settlement/pjs2-1-1.pdf
[105] AEP Texas North Division. Residential Service Schedule. Available at: https://www.aeptexas.com/account/bills/rates/AEPTexasRatesTariffsTX.aspx. Rate refers to the sum of the customer charge and metering charge.
[106] MD PSC. Case No. 9424. Order No. 88033. p. 27. February 15, 2017.
[107] Minnesota Power. Schedule Pg-1. Available at: https://www.mnpower.com/CustomerService/Rates
[108] MN PUC. Docket No. E002/GR-15-826. Findings of Fact, Conclusions and Order. p. 61. May 11, 2017. The Order left the existing charged unchanged, resulting in the current rate, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf
[109] Otter Tail Power Company ND. Residential Service Schedule. Available at: https://www.otpco.com/pricing/north-dakota/residential-rate-summary-nd/
[110] Idaho Power Company. Rate Schedule 1. Available at: https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/default.cfm?state=or
[111] SD PUC. Docket No. EL14-072. Order Adopting Settlement. June 17, 2015. See current Rate RS, available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/sdelectric/sd-elec.pdf
[112] Otter Tail Power Company. Residential Service. Available at: https://www.otpco.com/pricing/south-dakota/residential-rate-summary-sd/
[113] SWEPCO TX. Rate RS. Available at: https://swepco.com/account/bills/rates/SWEPCORatesTariffsTX.aspx

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114 Rocky Mountain Power UT. Residential Service. Available at: https://www.rockymountainpower.net/about/rar/uri.html. Rate refers to the monthly minimum bill, while the monthly fixed charge is slightly lower ($6.00).
115 Appalachian Power Company. Schedule RS. Available at: https://appalachianpower.com/account/bills/rates/APCORatesTariffsWV.aspx
116 MD PSC. Case No. 9406. Order No. 87591. p. 195. June 3, 2016.
117 FL PSC. Docket No. 160021-EI. Order No. PSC-0560-AS-EI. Exhibit A, p. 50. December 15, 2016.
118 SWEPCO AR. Rate Schedule No. 2. Available at: https://swepco.com/account/bills/rates/SWEPCORatesTariffsAR.aspx
119 Pacific Power WA. Rate Schedule 16. Available at: https://www.pacificpower.net/about/rr/wri.html
120 MD PSC. Case No. 9418. Order No. 87884. p. 110. November 15, 2016.
121 ME PUC. Docket No. 2015-00360. Final Order Part II. December 22, 2016. Order does not address rate design. See current Rate A (applicable to Bangor Hydro), available at: http://www.emeramaine.com/residential/rates/. Listed rate is the sum of the distribution service and stranded cost monthly charges.
122 MI PSC. Case No. U-18014. Final Decision. p. 110. January 31, 2017.
123 SD PUC. Docket EL15-024. Order Granting Joint Motion for Approval of Settlement Stipulation. June 15, 2016. See current Rate 10, available at https://www.montana-dakota.com/docs/default-source/rates-tariffs/sdElectric10. Stated charge is $0.247 per day, translating to a charge of $7.51/month.
124 Puget Sound Energy. Schedule 7. Available at: https://pse.com/aboutpse/Rates/Documents/elec_sch_007.pdf.
125 PA PUC. Docket R-2016-2537359. Order and Opinion. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Schedule 10, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/WPP-Tariff-40-with-Supp-29.pdf.
126 Indiana Michigan Power Company. Tariff RS. Available at: https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Indiana/IMINTB16-08-07-2017.pdf.
127 MI PSC. Case No. U-17698. Order Approving Settlement Agreement. August 14, 2015. See current Tariff RS, available at https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Michigan/IMMITB04-28-2017.pdf.
128 Pacific Power & Light Company. Schedule No. D. Available at https://www.pacificpower.net/content/dam/pacific_power/doc/About_Us/Rates_Regulation/California/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.
129 Entergy Louisiana. Schedule RS-L. Available at: http://www.entergy-louisiana.com/content/price/tariffs/LA/ell_elec_rs-l.pdf.
130 MA DPU. Docket 15-80. Final Decision. p. 319. April 29, 2016.
131 MI PSC. Case No. U-17990. Final Decision. p. 137. February 28, 2017.
132 NM PRC. Case No. 15-00127-UT. Final Order Partially Adopting Recommended Decision. p. 58. June 8, 2016.
133 NM PRC. Case No. 15-00261-UT. Final Order Partially Adopting Corrected Recommended Decision. September 28, 2016. See Rate No. 1A, available at https://www.pnm.com/documents/396023/396197/schedule_1_a.pdf/d9cfda9e-61a1-4008-ba3c-4152c9dbe7f1.
134 Entergy Texas. Schedule RS. Available at: http://www.entergy-texas.com/content/price/tariffs/eti_rs.pdf.
135 Dominion Energy (Virginia Electric and Power Company). Schedule 1. Available at: https://www.dominionenergy.com/library/domcom/pdfs/virginia-power/rates/shared/entire-filed-tariff.pdf.
136 PUCT. Docket No. 44941. Final Decision. p. 11. August 25, 2016.
137 Entergy Mississippi. Schedule RS-37C. Available at http://www.entergy-mississippi.com/content/price/tariffs/emi_rs-c.pdf.

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[138] AEP Texas - Central Division. Residential Service. Available at: https://www.aeptexas.com/global/utilities/lib/docs/ratesandtariffs/Texas/CentralDivTariffMar2017.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[139] CA PUC. Docket A.15-05-008. D.16-12-024. Decision Adopting a Modified All-Party Settlement. Exhibit F. December 1, 2016. See Schedule No. D-1, available at https://california.libertyutilities.com/uploads/August%202017%20Tariff%20Updates/D-1%20Aug%201%202017.pdf. The current version of Schedule No. D-1 reflects a charge of $8.17, but the CA PUC has not formally approved that charge. The associated tariff advice letter (E-72) is listed as suspended though the charge has been allowed to take effect.
[140] Eversource Energy (Eastern Massachusetts — Greater Boston). Rate R-1. Available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/120.pdf?sfvrsn=2 and https://www.eversource.com/Content/docs/default-source/rates-tariffs/190.pdf?sfvrsn=28.
[141] Bear Valley Electric Service. Schedule No. D. Available at: https://www.bves.com/media/managed/ratechange032217/D.pdf. Stated charge is $0.210 per day, translating to a monthly charge of $6.39.
[142] Eversource Energy (Western Massachusetts Electric Company). Schedule R-1. Available at https://www.eversource.com/Content/docs/default-source/rates-tariffs/1000.pdf?sfvrsn=2 and https://www.eversource.com/Content/docs/default-source/rates-tariffs/1052.pdf?sfvrsn=36.
[143] Duke Energy Ohio. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-oh/sheet-no-30-rate-rs-oh-e.pdf.
[144] SD PUC. Docket EL14-106. Order Approving Revised Settlement Stipulation. November 4, 2015. See current Rate No. 10, available at: http://www.northwesternenergy.com/docs/default-source/documents/sd_ne_rates/sd_elec/SouthDakotaElectricRateSchedule.
[145] ID PUC. Case No. AVU-E-16-03. Order No. 33682. December 28, 2016. See current Schedule 1, available at: https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/id/id_001.pdf.
[146] MA DPU. Docket 15-155. Final Decision. p. 475. September 30, 2016.
[147] Southwestern Electric Power Company (SWEPCO). Residential Service (Schedule RS). Available at https://www.swepco.com/global/utilities/lib/docs/ratesandtariffs/Louisiana/LouisianaA_06_06_2013.pdf.
[148] MT PSC. Docket No. D2015.6.51. Final Order. March 25, 2016. See current Rate 10, available at: https://www.montana-dakota.com/docs/default-source/rates-tariffs/mTelectric10. Stated charge is $0.17 per day, translating to a monthly charge of $5.17
[149] CenterPoint Energy Houston Electric. Residential Service. Available at: http://www.centerpointenergy.com/en-us/Documents/RatesandTariffs/HoustonElectric/CNP-Retail-Del-Tariff-Book-HOU.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[150] CO PUC. Docket 16AL-0048E. Decision Granting Motion to Approve Settlement. November 9, 2016. See current Schedule R, available at: https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf.
[151] Rocky Mountain Power. Residential Service (Schedule No. 1). Available at https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Idaho/Approved_Tariffs/Rate_Schedules/Residential_Service.pdf.
[152] Idaho Power Company. Schedule 1. Available at https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=156.
[153] The Potomac Edison Company. Schedule R. Available at https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/maryland/tariffs/PotomacEdisonRetailTariff.pdf.
[154] Alpena Power. Residential Service. Available at: http://www.alpenapower.com/wp-content/uploads/2014/09/Complete-Rate-Book-MPSC-9.pdf.
[155] NJ BPU. Docket ER17030308. Decision and Order Adopting Initial Decision and Stipulation of Settlement. p. 3. September 22, 2017.
[156] National Grid. Basic Residential Rate (A-16). Available at: https://www9.nationalgridus.com/narragansett/home/rates/4_a16.asp

[157] WV PSC. Case No. 14-0702-E-42T. Commission Order. February 3, 2015. See Monongahela Power Company Schedule A, available at: https://www.firstenergycorp.com/customer_choice/west_virginia/west_virginia_tariffs.html#gsc.tab=0
[158] NJ BPU. Docket ER16050428. Order Approving Stipulation. See Schedule E, Attachment 1, p. 7 of 28. February 22, 2017.
[159] Duke Energy Kentucky. Rate RS. Available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-ky/sheet-no-30-rate-rs-ky-e.pdf.
[160] Entergy Louisiana (Legacy EGSL Service Area). Schedule RS-G. Available at: http://www.entergy-louisiana.com/content/price/tariffs/GS/ell_elec_rs-g.pdf.
[161] Dayton Power & Light. Electric Distribution Service Residential (Tariff No. D17). Available at: https://www.dpandl.com/images/uploads/D17-Residential_3-24-15.pdf.
[162] NorthWestern Energy. Schedule No. REDS-1. Available at: http://www.northwesternenergy.com/docs/default-source/documents/mt_rates/Electric/REDS-1.
[163] Ohio Edison, Toledo Edison and The Illuminating Company. Rate RS. Available at: https://www.firstenergycorp.com/content/customer/customer_choice/ohio_/ohio_tariffs.html#gsc.tab=0
[164] Oncor Electric Delivery Company. Residential Service. Available at: http://www.oncor.com/EN/Documents/About%20Oncor/Billing%20Rate%20Schedules/Tariff%20for%20Retail%20Delivery%20Service.pdf. The charge indicated is sum of "Customer Charge" and "Metering Charge."
[165] NJ BPU. Docket ER16040383. Order Adopting Stipulation. December 12, 2016. See current Service Classification RS, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/New%20Jersey/tariffs/BPU-12-Part-III-Effective-9-1-2017.pdf.
[166] Public Service Electric and Gas Company (PSEG). Rate Schedule RS. Available at: https://www.pseg.com/family/pseandg/tariffs/electric/pdf/electric_tariff.pdf.
[167] From IOU rate cases for which applications were submitted from July 2014 onward. The table does not include interim rate increases allowed to take effect while the application officially remains pending. Instances where an application was dismissed or withdrawn have been removed. Where multiple rate cases involving the same utility were completed during the timeframe, all changes are included, resulting in some utilities being listed more than once. A total of 86 utilities are represented. Consequently, the averages do not reflect the average of current fixed charges both because some rates below have been superseded and because Tables 1 and 2 include a larger sample of utilities.
[168] AZ Corporation Commission. Docket No. E-01933A-15-0322. p. 186. Decision No. 75795. February 24, 2017.
[169] AZ Corporation Commission. Docket No. E-4204A-15-0142. Decision No. 75697. p. 66. August 18, 2016.
[170] AZ Corporation Commission. Docket No. E-01345A-16-0036. Decision No. 76364. September 19, 2017. Settlement Agreement. p. 17. Refers to the daily rate of $0.329 for Schedule R-XS applicable to customers with monthly use averaging 600 kWh or less. This replaces the former daily rate of $0.285 under Schedule E-12 as it existed prior to this proceeding.
[171] AR PSC. Docket No. 15-015-U. Final Order. February 23, 2016. See red-lined compliance tariffs resulting from final order at p. 437, available at: http://www.apscservices.info/pdf/15/15-015-U_376_1.pdf
[172] AR PSC. Docket No. 16-052-U. Order No. 8 Adopting Settlement. p. 9. May 18, 2017. See red-lined initially proposed tariffs for former fixed charge, available at: http://www.apscservices.info/pdf/16/16-052-U_43_7.pdf
[173] CA PUC. Docket A.15-05-008. D.16-12-024. Decision Adopting a Modified All-Party Settlement. Exhibit F. December 1, 2016. See Schedule No. D-1, available at https://california.libertyutilities.com/uploads/August%202017%20Tariff%20Updates/D-1%20Aug%201%202017.pdf. The current version of Schedule No. D-1 reflects a charge of $8.17, but the CA PUC has not formally approved that charge. The associated tariff advice letter (E-72) is listed as suspended though the charge has been allowed to take effect.
[174] CA PUC. Docket A.15-04-012. D.17-08-030. Decision Adopting Revenue Allocation and Rate Design for San Diego Gas & Electric Company. p. 31. August 24, 2017.

[175] CO PUC. Docket No. 16AL-0326E. Decision No. C16-1140. p. 36. December 19, 2016.
[176] CO PUC. Docket 16AL-0048E. Decision Granting Motion to Approve Settlement. November 9, 2016. See current Schedule R, available at: https://www.xcelenergy.com/staticfiles/xe/PDF/Regulatory/CO-Rates-&-Regulations-Entire-Electric-Book.pdf and red-lined tariffs filed with the initial proposal, available at: https://www.dora.state.co.us/pls/efi/efi.show_document?p_dms_document_id=664443&p_session_id=
[177] CT PURA. Docket No. 14-05-06. Decision dated December 17, 2014. p. 184 (adopted rate) and 190 (prior rate).
[178] CT PURA. Docket No. 16-06-04. Final Decision. p. 96. December 14, 2016. Order sets "maximum" test year customer charge of $8.50, but requires an adjustment for the overall rate increase. See current Rate R, available at: https://uinet.custhelp.com/cgi-bin/uinet.cfg/php/enduser/std_adp.php?p_faqid=3418 and initial proposed red-lined tariffs, available at: http://www.dpuc.state.ct.us/dockcurr.nsf/8e6fc37a54110e3e852576190052b64d/e422d52b1f01024185257fe300647cce?OpenDocument
[179] DE PSC. Docket No. 16-0649. Order No. 9048. Exhibit 2, p. 3. May 23, 2017.
[180] DC PSC. Docket No. FC 1139. Order No. 18846. p. 145. July 24, 2017.
[181] FL PSC. Docket No. 160021-EI. Order No. PSC-0560-AS-EI. Exhibit A, p. 50. December 15, 2016.
[182] FL PSC. Docket No. 160186-EI. Order No. PSC-17-0178-S-EI. p. 3. June 16, 2017. Order retains the existing residential rate structure. See Schedule RS, stating the charge as $0.65/day, translating to a monthly charge of $19.76, available at: https://www.gulfpower.com/residential/savings-and-energy/rates-and-billing/rates-rules-and-regulations and initially proposed red-lined tariffs, available at: http://www.psc.state.fl.us/library/filings/16/08160-16/08160-16.pdf
[183] ID PUC. Case No. AVU-E-16-03. Order No. 33682. p. 2. December 28, 2016. See also current Schedule 1, available at: https://www.myavista.com/-/media/myavista/content-documents/our-rates-and-tariffs/id/id_001.pdf
[184] ID PUC. Case No. AVU-E-15-05. Order No. 33437. p. 2 (existing charge) and p. 6 (providing for no increase in the charge). December 18, 2015.
[185] IN URC. Cause No. 44576. Final Order. p. 72. March 16, 2016.
[186] IN URC. Cause No. 44688. Final Order. p. 68 and 88. July 18, 2016.
[187] KS Corporation Commission. Docket No, 15-KCPE-116-RTS. Final Order. Attachment B, p. 4. September 10, 2015. Order adopted the settlement specifying the $14/month customer charge. See initially proposed red-lined tariffs for prior rate, available at: http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150102153029.pdf?Id=60a892a4-dca3-4c7a-b7c0-e27329605c63
[188] KS Corporation Commission. Docket No. 15-WSEE-115-RTS. Order Approving Stipulation .p. 22. September 24, 2015. Order adopted the settlement proposing a $14.50/month customer charge. See initially proposed red-lined tariffs for prior rate, available at: http://estar.kcc.ks.gov/estar/ViewFile.aspx/S20150302143551.pdf?Id=74e4c4cf-8c4d-4f30-95cc-59ce1417777b
[189] KY PSC. Docket No. 2014-00396. Final Order. p. 57-58. June 22, 2015.
[190] KY PSC. Docket No. 2016-00370. Final Order. p. 19. May 22, 2017.
[191] KY PSC. Docket No. 2014-00371. Final Order. p. 3. June 30, 2015.
[192] KY PSC. Docket No. 2014-00372. Final Order. p. 4. June 30, 2015.
[193] ME PUC. Docket No. 2015-00360. Final Order Part II. December 22, 2016. Order does not address rate design. See current Rate A (applicable to Bangor Hydro), available at: http://www.emeramaine.com/residential/rates/. Listed rate is the sum of the distribution service and stranded cost monthly charges. See also prior tariff, located at: https://mpuc-cms.maine.gov/CQM.Public.WebUI/MatterManagement/MatterFilingItem.aspx?FilingSeq=89421&CaseNumber=2015-00360
[194] MD PSC. Case No. 9406. Order No. 87591. p. 195. June 3, 2016.
[195] MD PSC. Case No. 9355. Order No. 86757. p. 28 (providing for no increase in the customer charge). December 12, 2014.
[196] MD PSC. Case No. 9424. Order No. 88033. p. 27. February 15, 2017.
[197] MD PSC. Case No. 9418. Order No. 87884. p. 110. November 15, 2016.

[198] MA DPU. Docket 15-155. Final Decision. p. 473-475. September 30, 2016.
[199] MA DPU. Docket 15-80. Final Decision. p. 318-319. April 29, 2016.
[200] MI PSC. Case No. U-17990. Final Decision. p. 137. February 28, 2017.
[201] MI PSC. Case No. U-17735. Final Decision. p. 101-102. November 19, 2015.
[202] MI PSC. Case No. U-18014. Final Decision. p. 109-110. January 31, 2017.
[203] MI PSC. Case No. U-17767. Final Decision. p. 120. December 11, 2015.
[204] MI PSC. Case No. U-17698. Order Approving Settlement Agreement. p. 2. August 14, 2015. See current Tariff RS, available at https://www.indianamichiganpower.com/global/utilities/lib/docs/ratesandtariffs/Michigan/IMMITB04-28-2017.pdf.
[205] MI PSC. Docket No. U-17895. Final Order. p. 55. September 8, 2016.
[206] MI PSC. Docket No. U-17669. Order Approving Settlement Agreement. Attachment A, p. 33. April 23, 2015. See initial rate design testimony (Beyer, p. 13) for prior rate, available at: http://efile.mpsc.state.mi.us/efile/docs/17669/0002.pdf
[207] MI PSC. Docket U-17710. Order Approving Settlement Agreement. Attachment A, Residential Service Schedule MR-1. March 23, 2015. See initial rate design testimony (Dahl, p. 12) for prior rate, available at: http://efile.mpsc.state.mi.us/efile/docs/17710/0001.pdf
[208] MN PUC. Docket No. E-017/GR-15-1033. Findings of Fact, Conclusions and Order. p. 75 (prior) and 84 (adopted). May 1, 2017.
[209] MN PUC. Docket No. E002/GR-15-826. Findings of Fact, Conclusions and Order. p. 61. May 11, 2017. The Order left the existing charged unchanged, resulting in the current rate, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/MN/Me_Section_5.pdf
[210] MS PSC. Docket No. 2015-UN-80. PSC Order. December 3, 2015. Base charge of $0.78 per day, translating to a monthly charge of $23.71. See current Rate R-55, available at: http://www.mississippipower.com/my-home/my-bill/pricing-and-rates
[211] MO PSC. Docket No. ER-2016-0179. Decision Approving Settlement. p. 12. March 8, 2017. Decision approved a $1/month increase, reflected in current rate SC-1, available at: https://www.ameren.com/missouri/rates/electric-full-service-bundle
[212] MO PSC. Docket No. ER-2014-0258. Report and Order. p. 76-77. April 29, 2015.
[213] MO PSC. Docket No. ER-2016-0023. Order Approving Stipulation and Agreement. p. 2. August 10, 2016. See initial rate design testimony (p. 9) for prior charge, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935963958
[214] MO PSC. Docket No. ER-2014-0351. Report and Order. p. 11. June 24, 2015.
[215] MO PSC. Docket No. ER-2016-0285. Report and Order. p. 57. May 3, 2017. See initial rate design testimony (Schedule MEM-3, p. 6) for prior customer charge, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936015684
[216] MO PSC. Docket No. ER-2014-0370. Report and Order. p. 88-89. September 2, 2015.
[217] MO PSC. Docket No. ER-2016-0156. Order Approving Stipulation. September 28, 2016. Order adopted a settlement resulting in the current rates. See the non-unanimous settlement, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=936033685. See initial rate design testimony (p. 19) for prior rate, available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/viewdocument.asp?DocId=935985987
[218] MT PSC. Docket No. D2015.6.51. Final Order. p. 9. March 25, 2016. See current Rate 10, available at: https://www.montana-dakota.com/docs/default-source/rates-tariffs/mTelectric10. Stated charge is $0.17 per day, translating to a monthly charge of $5.17
[219] PUCN. Docket No. 16-06006. Order Granting in Part and Denying Part General Rate Application by Sierra Pacific Power. December 22, 2016. See tariff compliance filing dated December 30, 2016 (Sheet 63G) showing no change in the residential customer charge, available at: http://pucweb1.state.nv.us/PDF/AxImages/DOCKETS_2015_THRU_PRESENT/2016-6/17802.pdf
[220] NH PUC. Docket No. DE 16-383. Order No. 26,005. p. 8. April 12, 2017. See initial filing of red-lined proposed permanent tariffs for prior rate, available at: http://puc.nh.gov/Regulatory/Docketbk/2016/16-383/INITIAL%20FILING%20-%20PETITION/16-383_2016-04-29_GSEC_DBA_LIBERTY_TARIFF_PERM_RATES.PDF

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[221] NH PUC. Docket No. DE 16-384. Order No. 26,007. p. 10-11. April 20, 2017. Order adopts a customer charge of $15/month, with a step adjustment effective May 1, 2017 to the current $15.24/month rate. See current Schedule D, available at: http://unitil.com/energy-for-residents/electric-information/tariffs and initial rate design testimony (p. 64) for prior rate, available at: http://puc.nh.gov/Regulatory/Docketbk/2016/16-384/INITIAL%20FILING%20-%20PETITION/16-384_2016-04-29_UES_DTESTIMONY_H_OVERCAST.PDF
[222] NJ BPU. Docket ER16030252. Order Adopting Stipulation of Settlement for the Base Rate Case and Establishing a Phase II to Review the PowerAhead Program at the BPU. p. 5. August 24, 2016.
[223] NJ BPU. Docket ER17030308. Decision and Order Adopting Initial Decision and Stipulation of Settlement. p. 3. September 22, 2017.
[224] NJ BPU. Docket ER16040383. Order Adopting Stipulation. Attachment 2, p. 2. December 12, 2016. See current Service Classification RS, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/New%20Jersey/tariffs/BPU-12-Part-III-Effective-9-1-2017.pdf.
[225] NJ BPU. Docket ER16050428. Order Approving Stipulation. See Schedule E, Attachment 1, p. 7 of 28. February 22, 2017.
[226] NM PRC. Case No. 15-00127-UT. Final Order Partially Adopting Recommended Decision. p. 58. June 8, 2016.
[227] NM PRC. Case No. 15-00261-UT. Final Order Partially Adopting Corrected Recommended Decision. p. 80 (referring to amount of current charge and requested increase). September 28, 2016. See Rate No. 1A, available at https://www.pnm.com/documents/396023/396197/schedule_1_a.pdf/d9cfda9e-61a1-4008-ba3c-4152c9dbe7f1.
[228] NM PRC. Docket No. 16-00296-UT. Final Order Adopting Stipulation. August 10, 2016. See current Rate No. 1, available at: https://www.xcelenergy.com/staticfiles/xe/Regulatory/Regulatory%20PDFs/rates/NM/nm_sps_e_entire.pdf and initial rate design testimony (Attachment RML-7, p. 1) for prior rates, available at: http://164.64.85.108/infodocs/2015/10/PRS20215104DOC.PDF
[229] NY PSC. Case No. 14-E-0318. Order Approving Rate Plan. p. 57. June 17, 2016. Order rejected settlement providing for an increase in the fixed charge, retaining it at $24.00/month. See current SC-1 rate, available at: https://www.cenhud.com/rates/index
[230] NY PSC. Case No. 16-E-0060. Order Approving Electric Rate Plan. January 25, 2017. Order adopted a joint party proposal maintaining the existing rate. See Schedule SC-1, available at: https://www2.dps.ny.gov/ETS/jobs/display/download/6090846.pdf
[231] NY PSC. Case No. 15-E-0050. Order Adopting Proposal to Extend Rate Plan. June 19, 2015. Proposal extended existing SC-1 rates for one year, unchanged.
[232] NY PSC. Case No. 15-E-0283. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current NYSEG Rate SC-1, available at: http://www.nyseg.com/SuppliersAndPartners/pricingandtariffs/electricitytariffs/PSC120TableOfContents.html
[233] NY PSC. Case No. 14-E-0493. Order Establishing Rate Plan. Appendix 18, Schedule 1. October 16, 2015. See also p. 11 describing the rate plan, which does not include any customer charge increases.
[234] NY PSC. Case No. 15-E-0285. Order Approving Electric and Gas Rate Plans. p. 21. June 15, 2016. See current RGE Rate SC-1, available at: https://www.rge.com/SuppliersAndPartners/pricingandtariffs/tariffratesummaries/psc19.html
[235] NCUC. Docket No. E-22, Sub 532. Order Approving Rate Increase. p. 16. December 22, 2016. Adopted settlement provides for no customer charge increase, retaining the existing rate. See Schedule 1, available at: https://www.dominionenergy.com/library/domcom/pdfs/north-carolina-power/rates/shared/entire-filing.pdf?la=en
[236] ND PSC. Case No. PU-16-666. Findings of Fact, Conclusions of Law and Order. p. 6. June 16, 2017. Charge is stated as $0.46/day, translating to a monthly charge of $13.98. See initially proposed red-lined tariffs for prior rate, available at: http://www.psc.nd.gov/database/documents/16-0666/003-020.pdf
[237] OK Corporation Commission. Cause No. PUD 201500273. Order No. 662059. p. 4. March 20, 2017. Order adopts the ALJ recommendation, retaining the existing customer charge at $13. See Schedule R-1,

available at: https://oge.com/wps/wcm/connect/81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045/3.00+R-1.pdf?MOD=AJPERES&CACHEID=81687ef5-a4b0-4b0f-b8a0-1cfaa22b1045
[238] OK Corporation Commission. Cause No. PUD 201500208. Order No. 657877. p. 143 (discussing existing customer charge). November 10, 2016. See current Schedule RS, available at: https://www.psoklahoma.com/account/bills/rates/.
[239] OR PUC. Docket No. UE 294. Order No. 15-356. p. 11. November 3, 2015.
[240] PA PUC. Docket No. R-2016-2531550. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See current Schedule RS, available at: https://www.citizenselectric.com/TariffStart.asp and initial filing detailing prior charges (p. 7) available at: http://www.puc.pa.gov/pcdocs/1471660.pdf
[241] PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0n and the initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436865.pdf
[242] PA PUC. Docket No. R-2014-2428745. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341067.pdf
[243] PA PUC. Docket No. R-2015-2468981. Opinion and Order. p. 11. December 17, 2015. See Settlement Exhibit A with red-line settlement tariffs for prior charge (tariff p. 45), available at: http://www.puc.state.pa.us/pcdocs/1381271.pdf
[244] PA PUC. Docket No. R-2016-2537352. Opinion and Order. p. 11. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0 and the initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436873.pdf
[245] PA PUC. Docket No. R-2014-2428743. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341079.pdf
[246] PA PUC. Docket No. R-2016-2537355. Opinion and Order. p. 13. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Rate RS, available at: https://www.firstenergycorp.com/content/customer/customer_choice/pennsylvania/pennsylvania_tariffs.html#gsc.tab=0 and initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436874.pdf
[247] PA PUC. Docket No. R-2014-2428744. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341065.pdf
[248] PA PUC. Docket No. R-2015-2469275. Opinion and Order. p. 8. November 19, 2015.
[249] PA PUC. Docket No. R-2016-2531551. Final Order. April 6, 2017. The Order approved a party settlement, resulting in the current rates. See Schedule No. 1, available at: https://wellsboroelectric.com/wp-content/uploads/2014/03/Distribution-Tariff-Supp-106-Apr-11-2017.pdf and initial filing detailing prior charges (p. 6) available at: http://www.puc.pa.gov/pcdocs/1471646.pdf
[250] PA PUC. Docket R-2016-2537359. Order and Opinion. January 19, 2017. Order approved a party settlement resulting in the current rates. See current Schedule 10, available at: https://www.firstenergycorp.com/content/dam/customer/Customer%20Choice/Files/PA/tariffs/WPP-Tariff-40-with-Supp-29.pdf and initial filing with red-lined tariff proposals, available at: http://www.puc.state.pa.us/pcdocs/1436870.pdf
[251] PA PUC. Docket No. R-2014-02428742. Final Order. p. 3. April 9, 2015. Order adopts settlement but does not discuss rate design. See Settlement Exhibit 4, p. 1 detailing current and proposed rates, available at: http://www.puc.state.pa.us/pcdocs/1341050.pdf
[252] SC PSC. Docket No. 2016-227-E. Order Approving Settlement. December 21, 2016. See current rate Schedule RES, available at: https://www.duke-energy.com/_/media/pdfs/for-your-home/rates/electric-

sc/r1scscheduleres.pdf?la=en and initially proposed red-lined tariffs detailing the prior rate, available at: https://dms.psc.sc.gov/Attachments/Matter/6ee58943-f5e3-4b43-b35d-1f6294305b39

[253] SD PUC. Docket No. EL14-072. Order Adopting Settlement. June 17, 2015. See current Rate RS, available at: https://www.midamericanenergy.com/content/pdf/rates/elecrates/sdelectric/sd-elec.pdf and Settlement Exhibit PJS-4, Schedule 2-1 showing prior and adopted rates, available at: http://www.puc.sd.gov/commission/dockets/electric/2014/el14-072/pjs4-2-1.pdf

[254] SD PUC. Docket EL15-024. Order Granting Joint Motion for Approval of Settlement Stipulation. June 15, 2016. See current Rate 10, available at https://www.montana-dakota.com/docs/default-source/rates-tariffs/sdElectric10. Stated charge is $0.247 per day, translating to a charge of $7.51/month. For prior rates, see Settlement Exhibit EJP-2, Schedule 2-1, available at: https://puc.sd.gov/commission/dockets/electric/2015/EL15-024/memo/EJP-2-2-1.pdf

[255]SD PUC. Docket EL14-106. Order Approving Revised Settlement Stipulation. November 4, 2015. See current Rate No. 10, available at: http://www.northwesternenergy.com/docs/default-source/documents/sd_ne_rates/sd_elec/SouthDakotaElectricRateSchedule and Settlement Exhibit EJP-2, Schedule 2-1 for prior rates, available at: https://puc.sd.gov/commission/dockets/electric/2014/EL14-106/memo/EJP-2-2-1.pdf

[256] SD PUC Docket No. EL14-058. Order Adopting Settlement. June 16, 2015. See Settlement Exhibit PJS-2, Schedule 2-1 for prior and adopted rates, available at: http://puc.sd.gov/commission/dockets/electric/2014/EL14-058/settlement/pjs2-1-1.pdf

[257] TN Regulatory Authority. Docket No. 1600001. Order Approving Stipulation. Attachment C, Schedule 1. October 19, 2016.

[258] PUCT. Docket No. 44941. Final Decision. p. 11. August 25, 2016. See initial rate design testimony (Schichtl, p. 23) for prior rates, available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/44941_2_861552.PDF

[259] PUCT. Control No. 45524. Order Adopting Settlement. January 26, 2017. See current Residential Service schedule, available at: https://www.xcelenergy.com/company/rates_and_regulations/rates/texas_rates,_rights,_&_service_rules and initial rate design testimony (Luth, p. 45) for prior rate, available at: http://interchange.puc.state.tx.us/WebApp/Interchange/Documents/45524_2_882623.PDF

[260] PUCT. Control No. 43965. Final Order. p. 54. December 18, 2015.

[261] VA Corporation Commission. Docket No. PUC-2015-00063. Final Order. p. 5. February 2, 2016

[262] WA UTC. Docket No. UE-160228. p. 57. Final Order Rejecting Tariff Filing. December 15, 2016. Commission determined that the existing rates were just and reasonable and therefore retained them. See Rate Schedule No. 1, available at: https://myavista.com/about-us/our-rates-and-tariffs/washington-electric-resources

[263] WA UTC. Docket No. UE-150204. Final Order. p. 10. January 6, 2016.

[264] WI PSC. Docket No. 660-UR-120. Final Decision. p. 7 (adopted rate) and 35 (prior rate). December 22, 2016.

[265] WI PSC. Docket No. 3270-UR-121. Final Decision. Appendix B, p. 2. December 15, 2016.

[266] WI PSC. Docket No. 4280-ER-106. Final Decision. Appendix D, p. 1. June 20, 2017.

[267] WI PSC. Docket No. 5820-UR-114. Final Decision. Appendix B, page 2 of 6. August 10, 2017.

[268] WI PSC. Docket No. 6690-UR-124. Final Decision. p. 63. December 17, 2015.

[269] WI PSC. Docket No. 4220-UR-122. Final Decision. Appendix B, p. 2. December 1, 2016.

[270] WI PSC. Docket No. 4220-UR-121. Final Decision. Appendix B, p. 2. December 23, 2015.

[271] WY PSC. Docket No. 14409. Order No. 23958. Appendix A, p. 11. April 6, 2017. Charge is stated as $0.822/day, translating to a monthly charge of $25.00/month.

[272] WY PSC. Docket No. 14076. Order No. 23208. December 30, 2015. See current Schedule 2 available at: https://www.rockymountainpower.net/about/rar/wri.html. See initially proposed red-line tariffs for reference to prior rate, available at: https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Wyoming/Regulatory_Filings/Docket_20000_469_ER_15/03-02-15_Direct_Testimony_and_Exhibits/Joelle_R_Steward/exhibits/Exhibit_RMP_JRS_8.pdf

DUKE ENERGY PROGRESS, LLC

Docket E-2, SUB 1142 E1 Item #45E Unit Costs per Cost of Service "Proforma Adjusted at Proposed Rates"

NORTH CAROLINA RETAIL COST OF SERVICE STUDY

TEST YEAR ENDING DECEMBER 31 2016

Summer 1 CP Demand Allocation **without Minimum System**

UNIT COST DETAIL - REVENUES		NC RETAIL	NC RES	NC SGS	NC SGSCLR	NC MGS	NC LGS	NC SI	NC TSS	NC ALS	NC SLS	NC SFL
TOTAL FUNCTIONALIZED REVENUES	PROD_DEMAND	1,369,897,446	678,858,820	91,904,285	924,708	384,781,223	210,502,901	2,763,552	161,955	1	0	0
	PROD_ENERGY	1,309,183,127	520,350,599	64,189,541	949,306	416,715,073	296,920,697	1,986,158	192,959	6,000,232	1,855,933	22,627
	TRANSMISSION	160,678,187	80,554,669	11,203,377	133,194	43,988,327	24,489,967	286,371	22,282	0	0	0
	DIST_SUBS	75,878,078	47,803,597	4,948,242	29,424	14,685,808	7,248,787	306,390	6,155	669,034	136,032	44,609
	DIST_PRIMARY	291,281,999	191,659,593	19,661,675	108,757	59,803,430	15,537,373	1,297,865	23,199	2,465,691	538,566	185,850
	DIST_L_XFMR	84,505,908	56,200,852	5,906,604	37,570	17,012,604	3,987,103	334,959	7,714	856,409	162,094	0
	DIST_SEC_SERV	170,573,039	64,749,052	6,642,273	37,555	15,275,480	0	142,206	7,968	53,136,485	30,582,021	0
	CUSTOMER	155,511,492	127,362,365	17,670,273	729,081	8,574,270	827,359	168,539	57,926	492	107,468	13,719
	Total	3,617,509,276	1,767,539,547	222,126,271	2,949,596	960,836,215	559,514,188	7,286,040	480,158	63,128,342	33,382,115	266,806
TOTAL SALES OF ELECTRICITY	PROD_DEMAND	1,363,275,689	674,665,361	91,323,505	914,591	383,585,287	209,874,128	2,752,711	160,104	1	0	0
	PROD_ENERGY	1,296,904,427	518,073,176	63,814,957	939,583	415,806,065	291,633,396	1,982,853	190,983	4,400,756	40,113	22,545
	TRANSMISSION	155,475,630	77,932,130	10,857,787	129,813	42,570,460	23,689,059	274,733	21,648	0	0	0
	DIST_SUBS	74,410,228	46,848,549	4,852,775	28,863	14,421,019	7,113,228	299,634	6,026	662,589	133,891	43,655
	DIST_PRIMARY	277,357,591	182,375,229	18,746,633	104,561	56,940,486	14,856,387	1,225,426	22,210	2,395,345	515,431	175,884
	DIST_L_XFMR	82,546,543	54,864,693	5,772,864	36,803	16,630,192	3,903,012	325,341	7,539	847,092	159,007	0
	DIST_SEC_SERV	168,125,688	63,643,827	6,531,645	36,886	15,050,889	0	139,706	7,814	52,573,738	30,141,184	0
	CUSTOMER	146,890,407	120,073,645	16,678,966	692,541	8,297,971	818,608	162,225	53,019	492	99,745	13,196
	Total	3,564,986,203	1,738,476,610	218,579,131	2,883,641	953,302,369	551,887,818	7,162,628	469,343	60,880,012	31,089,372	255,280
NON REQ'T SALES REVENUE	PROD_DEMAND	4,745,039	2,290,455	297,116	2,132	1,371,513	772,249	11,157	418	0	0	0
	PROD_ENERGY	99,558,959	41,512,521	5,005,046	73,047	29,710,813	22,073,765	141,497	15,132	771,627	252,370	3,142
	TRANSMISSION	302,534	146,035	18,944	136	87,445	49,237	711	27	0	0	0
	DIST_SUBS	0	0	0	0	0	0	0	0	0	0	0
	DIST_PRIMARY	0	0	0	0	0	0	0	0	0	0	0
	DIST_L_XFMR	0	0	0	0	0	0	0	0	0	0	0
	DIST_SEC_SERV	0	0	0	0	0	0	0	0	0	0	0
	CUSTOMER	0	0	0	0	0	0	0	0	0	0	0
	Total	104,606,533	43,949,011	5,321,105	75,315	31,169,771	22,895,252	153,366	15,576	771,627	252,370	3,142
FUNCTIONALIZED REQ'TS RATE SCHED REV	PROD_DEMAND	1,358,530,649	672,374,906	91,026,389	912,460	382,213,774	209,101,879	2,741,554	159,686	1	0	0
	PROD_ENERGY	1,197,345,467	476,560,655	58,809,911	866,536	386,095,252	269,559,631	1,841,356	175,851	3,629,129	(212,257)	19,403
	TRANSMISSION	155,173,096	77,786,095	10,838,843	129,677	42,483,015	23,639,822	274,022	21,621	0	0	0
	DIST_SUBS	74,410,228	46,848,549	4,852,775	28,863	14,421,019	7,113,228	299,634	6,026	662,589	133,891	43,655
	DIST_PRIMARY	277,357,591	182,375,229	18,746,633	104,561	56,940,486	14,856,387	1,225,426	22,210	2,395,345	515,431	175,884
	DIST_L_XFMR	82,546,543	54,864,693	5,772,864	36,803	16,630,192	3,903,012	325,341	7,539	847,092	159,007	0
	DIST_SEC_SERV	168,125,688	63,643,827	6,531,645	36,886	15,050,889	0	139,706	7,814	52,573,738	30,141,184	0
	CUSTOMER	146,890,407	120,073,645	16,678,966	692,541	8,297,971	818,608	162,225	53,019	492	99,745	13,196
	Total	3,460,379,670	1,694,527,599	213,258,026	2,808,326	922,132,598	528,992,566	7,009,263	453,767	60,108,385	30,837,002	252,138
Revenues for Rate Design: Including Proposed Increase												
Present Revenues per Bateman Exhibit 2, col. (E)		2,982,637,109	1,450,543,402	186,688,488	2,797,243	790,856,356	461,145,607	5,239,884	440,975	59,969,687	24,775,322	180,146
Minus: Adjustments to Exclude per Bateman Exhibit 2, col. (Q)		(8,375,509)	(14,303,526)	567,624	(6,052)	3,027,087	2,620,261	(22,716)	9,815	(192,120)	(79,370)	3,489
Plus: Target Revenue Increase for Rate Design per Bateman Exhibit 2, col. (S)		476,042,397	240,906,428	26,596,179	11,388	131,330,136	69,146,393	1,758,619	13,046	4,392,171	1,814,541	73,497
Proposed Revenues for Rate Design		3,450,303,997	1,677,146,304	213,852,291	2,802,579	925,213,579	532,912,260	6,975,787	463,835	64,169,738	26,510,493	257,131

DUKE ENERGY PROGRESS, LLC

Docket E-2, SUB 1142 E1 Item #45E Unit Costs per Cost of Service "Proforma Adjusted at Proposed Rates"

NORTH CAROLINA RETAIL COST OF SERVICE STUDY

TEST YEAR ENDING DECEMBER 31 2016

Summer 1 CP Demand Allocation **without Minimum System**

UNIT COST DETAIL - REVENUES		NC RETAIL	NC RES	NC SGS	NC SGSCLR	NC MGS	NC LGS	NC SI	NC TSS	NC ALS	NC SLS	NC SFL
FUNCT REQ'TS RATE SCHED REV for RATE DESIGN	PROD_DEMAND	1,354,702,549	665,478,148	91,280,043	910,592	383,490,807	210,651,268	2,728,460	163,229	1	0	0
	PROD_ENERGY	1,196,177,191	471,672,425	58,973,791	864,763	387,385,253	271,556,996	1,832,562	179,752	3,874,339	(182,477)	19,788
	TRANSMISSION	154,721,436	76,988,219	10,869,047	129,412	42,624,957	23,814,987	272,713	22,101	0	0	0
	DIST_SUBS	74,069,593	46,368,009	4,866,298	28,803	14,469,202	7,165,935	298,202	6,160	707,359	115,106	44,519
	DIST_PRIMARY	275,926,919	180,504,550	18,798,873	104,347	57,130,732	14,966,469	1,219,573	22,702	2,557,191	443,114	179,367
	DIST_L_XFMR	82,117,815	54,301,929	5,788,951	36,728	16,685,756	3,931,932	323,787	7,706	904,328	136,698	0
	DIST_SEC_SERV	166,864,167	62,991,013	6,549,846	36,810	15,101,176	0	139,038	7,988	56,125,996	25,912,300	0
	CUSTOMER	145,724,326	118,842,012	16,725,443	691,124	8,325,696	824,674	161,450	54,195	525	85,751	13,457
	Total	3,450,303,997	1,677,146,304	213,852,291	2,802,579	925,213,579	532,912,260	6,975,787	463,835	64,169,738	26,510,493	257,131
				-	-	-	-	-	-	-	-	-
FUNCT REVENUE for RATE DESIGN	**Demand**	2,108,402,479	1,086,631,867	138,153,056	1,246,692	529,502,631	260,530,591	4,981,775	229,887	60,294,875	26,607,219	223,886
	Energy	1,196,177,191	471,672,425	58,973,791	864,763	387,385,253	271,556,996	1,832,562	179,752	3,874,339	(182,477)	19,788
	Customer	145,724,326	118,842,012	16,725,443	691,124	8,325,696	824,674	161,450	54,195	525	85,751	13,457
		3,450,303,997	1,677,146,304	213,852,291	2,802,579	925,213,579	532,912,260	6,975,787	463,835	64,169,738	26,510,493	257,131
Billing Determinants	Summer CP kW (DP adj @ meter)		3,590,538	465,763	3,341	2,152,346	1,225,837	17,542				
	Adj kWh Sales (E2 at meter)		15,485,331,177	1,867,042,693	27,248,688	11,104,978,096	8,346,014,079	53,055,810	5,644,587			1,182,005
	Year End No. Cust (C1)		1,159,461	156,878	5,095	37,744	278	891	848			
<u>**Unit Cost per Billing Determinants**</u>												
	Demand $/kW-Month		25.22	24.72	31.09	20.50	17.71	23.67	N/A	N/A	N/A	N/A
	Energy ¢/kWh		3.05	3.16	3.17	3.49	3.25	3.45	3.18	N/A	N/A	1.67
	Cust $/Month		**8.54**	8.88	11.30	18.38	247.20	15.10	5.33	N/A	N/A	N/A
Unit Costs - ¢/kWh	Demand		7.02	7.40	4.58	4.77	3.12	9.39	4.07	N/A	N/A	18.94
	Energy		3.05	3.16	3.17	3.49	3.25	3.45	3.18	N/A	N/A	1.67
	Customer		0.77	0.90	2.54	0.07	0.01	0.30	0.96	N/A	N/A	1.14
	Total		10.83	11.45	10.29	8.33	6.39	13.15	8.22	N/A	N/A	21.75

DUKE ENERGY PROGRESS, INC.
Docket E-2, SUB 1142 E1 Item #45C "Proforma Adjusted at Proposed Rates"
NORTH CAROLINA RETAIL COST OF SERVICE STUDY
TEST YEAR ENDING December 31, 2016

NCUC Form E-1
Item No. 45C COS "PROFORMA ADJUSTED"

Summer CP Demand Allocation without MINIMUM SYSTEM

COS DETAIL - REVENUES	NC RETAIL	NC RES	NC SGS	NC SGSCLR	NC MGS	NC LGS	NC SI	NC TSS	NC ALS	NC SLS	NC SFL
SALES OF ELECTRICITY:											
RETAIL SALES OF ELECTRICITY	3,342,615,512	1,645,628,092	210,862,429	3,136,646	876,347,348	508,129,399	5,775,485	516,093	65,528,071	26,484,933	207,015
REV - REPS	33,231,855	16,183,936	11,582,770	410,491	3,592,458	123,965	42,421	54,590	1,137,812	98,927	4,486
REV - DERP	0	0	0	0	0	0	0	0	0	0	0
REV UNBILLED REVENUES	18,246,968	16,709,214	278,788	4,194	922,044	72,020	7,607	(943)	227,184	26,584	277
REV - SALES FOR RESALE D/A	0	0	0	0	0	0	0	0	0	0	0
REV - SALES FOR RESALE CREDIT - TRANSMISSION	302,534	146,035	18,944	136	87,445	49,237	711	27	0	0	0
REV - SALES FOR RESALE CREDIT - ENERGY	99,558,959	41,512,521	5,005,046	73,047	29,710,813	22,073,765	141,497	15,132	771,627	252,370	3,142
REV - SALES FOR RESALE CREDIT - DEMAND	4,745,039	2,290,455	297,116	2,132	1,371,513	772,249	11,157	418	0	0	0
REV - PROV FOR RATE REFUND	699,832	424,452	49,376	730	203,527	18,311	1,387	150	1,407	487	6
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TOTAL SALES OF ELECTRICITY	3,499,400,700	1,722,894,704	228,094,468	3,627,376	912,235,148	531,238,947	5,980,266	585,466	67,666,100	26,863,300	214,925
OTHER REVENUES:											
REV - FORFEITED DISCOUNTS (450) AS INPUT	6,901,021	5,871,415	794,417	25,801	191,132	1,408	4,512	4,294	0	7,662	380
REV - MISC SERVICE REVENUES (451)	6,934,417	5,899,828	798,262	25,926	192,057	1,415	4,534	4,315	0	7,699	382
REV - RENT (454) - DIST PLT REL	3,430,750	2,107,086	218,171	2,106	590,978	143,996	13,596	191	202,637	150,727	1,263
REV - RENT (454) - DIST POLE RENTAL REV	9,496,819	6,227,509	608,059	2,329	2,049,813	482,800	51,572	561	50,633	16,560	6,983
REV - RENT (454) - TRANS PLT REL	378,818	182,858	23,720	170	109,494	61,652	891	33	0	0	0
REV - RENT (454) - ADD FAC - WHLS	0	0	0	0	0	0	0	0	0	0	0
REV - RENT (454) - ADD FAC - RET x LIGHTING	5,426,033	21	63,207	0	395,718	4,967,087	0	0	0	0	0
REV - RENT (454) - ADD FAC - LIGHTING	3,398,411	0	0	0	0	0	0	0	1,586,359	1,812,052	0
REV - RENT (454) - OTHER	4,770,351	2,496,144	300,019	2,420	1,202,127	603,258	13,551	378	86,924	64,985	546
REV - OTHER ELEC REV (456) - PROD PLT REL	791,932	382,270	49,588	356	228,901	128,886	1,862	70	0	0	0
REV - OTHER ELEC REV (456) - TRANS REL	3,950,457	1,906,906	247,362	1,775	1,141,845	642,932	9,289	348	0	0	0
REV - OTHER ELEC REV (456) - GEN PLT REL	(171,196)	(96,358)	(11,149)	(135)	(37,255)	(17,600)	(498)	(20)	(4,450)	(3,699)	(33)
REV - OTHER ELEC REV (456) - WH D/A	0	0	0	0	0	0	0	0	0	0	0
REV - OTHER ELEC REV (456) - OTHER	601,449	314,715	37,827	305	151,565	76,059	1,708	48	10,959	8,193	69
REV - OTHER ELEC REV (456) - REPS	57,084	27,800	19,896	705	6,171	213	73	94	1,954	170	8
REV - OTHER ELEC REV (456) - OTHER ENERGY	1,637,349	682,716	82,313	1,201	488,625	363,026	2,327	249	12,690	4,150	52
REV - OTHER ELEC REV (456) - DIS PLT REL	5,115,419	3,141,770	325,304	3,140	881,177	214,705	20,273	284	302,142	224,741	1,883
REV - OTHER NC RETAIL SPECIFIC	(196,040)	(81,742)	(9,855)	(144)	(58,503)	(43,465)	(279)	(30)	(1,519)	(497)	(6)
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TOTAL OTHER REVENUES	52,523,072	29,062,937	3,547,140	65,955	7,533,846	7,626,370	123,411	10,814	2,248,330	2,292,743	11,526
BOOK REVENUES	3,551,923,773	1,751,957,641	231,641,608	3,693,331	919,768,993	538,865,317	6,103,677	596,280	69,914,430	29,156,043	226,451
Functionalized Book Revenues	3,394,794,167	1,678,945,693	222,773,363	3,552,061	881,065,377	508,343,696	5,826,900	569,890	66,894,473	26,610,930	211,784
REVENUE ADJUSTMENTS:											
ADJREV UNBILLED REVENUES	(18,246,968)	(16,709,214)	(278,788)	(4,194)	(922,044)	(72,020)	(7,607)	943	(227,184)	(26,584)	(277)
RETAIL SALES OF ELECTRICITY ADJ TO EXC DSM & REPS	(368,353,912)	(209,388,216)	(23,606,317)	(345,456)	(82,463,905)	(44,363,532)	(558,318)	(65,304)	(5,676,340)	(1,863,145)	(23,381)
REV - REPS ADJUSTMENT	(33,289,000)	(16,211,765)	(11,602,687)	(411,197)	(3,598,636)	(124,178)	(42,494)	(54,684)	(1,139,768)	(99,097)	(4,493)
RETAIL ADJ TO EXC JAAR: PROD DEM REL REV	1,760,000	849,561	110,204	791	508,713	286,438	4,138	155	0	0	0
ADJREV WEATHER NORMALIZATION	(14,521,149)	701,108	(2,196,292)	(32,737)	(8,900,227)	(4,093,000)	0	0	0	0	0
REV - HURRICAN MATTHEW REVENUE ADJ	12,138,658	6,759,419	799,668	11,790	3,918,140	496,739	22,716	185	117,956	11,534	511
ADJREV CUSTOMER GROWTH	10,758,000	6,843,000	829,000	27,000	1,955,000	976,000	0	(10,000)	0	142,000	(4,000)
Incr/(Decr) to REV - MISC SERVICE REVENUES (451)	(226,009)	(192,290)	(26,017)	(845)	(6,260)	(46)	(148)	(141)	(0)	(251)	(12)
Incr/(Decr) to REV - RENT (454) - ADD FAC	(2,030,772)	(407,422)	(63,555)	(395)	(287,529)	(1,244,714)	(2,212)	(62)	(14,188)	(10,607)	(89)
Incr/(Decr) to REV - OTHER ELEC REV (456) - OTHER	(94,823)	(49,617)	(5,964)	(48)	(23,895)	(11,991)	(269)	(8)	(1,728)	(1,292)	(11)
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Total ADJUSTMENT TO MISC REVENUE	(2,351,604)	(649,329)	(95,536)	(1,288)	(317,684)	(1,256,751)	(2,629)	(210)	(15,915)	(12,149)	(112)
ADJREV COAL INVENTORY RIDER REV	196,000	81,725	9,853	144	58,491	43,456	279	30	1,519	497	6
RETAIL SALES OF ELECTRICITY PROPOSED ADJ	477,495,478	243,305,617	26,515,558	11,413	130,829,373	68,755,718	1,766,277	12,761	153,644	6,073,015	72,101
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TOTAL REVENUE ADJUSTMENTS	65,585,503	15,581,906	(9,515,337)	(743,735)	41,067,221	20,648,870	1,182,362	(116,123)	(6,786,088)	4,226,071	40,355
TOTAL ADJUSTED REVENUE	3,617,509,276	1,767,539,547	222,126,271	2,949,596	960,836,215	559,514,188	7,286,040	480,158	63,128,342	33,382,115	266,806
Functionalized Adjusted Revenues	3,460,379,670	1,694,527,599	213,258,026	2,808,326	922,132,598	528,992,566	7,009,263	453,767	60,108,385	30,837,002	252,138

DUKE ENERGY PROGRESS, LLC
DOCKET NO. E-2, SUB 1142
SPREAD OF PROPOSED INCREASE TO CUSTOMER CLASSES
(DOLLARS IN THOUSANDS)
NORTH CAROLINA RETAIL

Line No.	Rate Class	Rate Base (A)	Present Rate Revenues Excl DSM/EE (B)	Net Operating Income (C)	Present ROR (D)	Gross Revenues At Average ROR (E)	Variance From The Average (F)	25.0% Reduction in Variance From The Average (G)	Proposed Rate Increase Before Reduction in Variance (H)	Proposed Rate Increase After Reduction in Variance (I)	Present Rate Revenues Incl DSM/EE, JAAR and REPS (J)	Proposed Percent Increase (K)	ROR At Proposed Rates (L)
		E-1 Item 45b	E-1 Item 45b, Summer CP	E-1 Item 45b	(C) / (A)		(B) - (E)	- (F) * 25%		(H) + (G)		(I) / (J)	
1	**RES**	$ 4,219,172	$ 1,450,543	$ 180,346	4.27%	$ 1,432,018	$ 18,526	$ (4,631)	$ 247,937	$ 243,306	$ 1,600,067	**15.2%**	7.86%
2	**SGS**	$ 502,369	$ 186,688	$ 27,653	5.50%	$ 174,665	$ 12,023	$ (3,006)	$ 29,521	$ 26,516	$ 215,430	**12.3%**	8.78%
3	**SGSCLR**	$ 3,836	$ 2,797	$ 692	18.04%	$ 1,941	$ 856	$ (214)	$ 225	$ 11	$ 3,597	**0.3%**	18.16%
4	**MGS**	$ 2,063,200	$ 790,856	$ 58,353	2.83%	$ 829,203	$ (38,347)	$ 9,587	$ 121,243	$ 130,829	$ 820,724	**15.9%**	6.78%
5	**LGS**	$ 1,041,713	$ 461,146	$ 22,665	2.18%	$ 491,306	$ (30,160)	$ 7,540	$ 61,216	$ 68,756	$ 475,051	**14.5%**	6.29%
6	**SI**	$ 23,342	$ 5,240	$ (60)	-0.26%	$ 6,818	$ (1,578)	$ 395	$ 1,372	$ 1,766	$ 5,476	**32.3%**	4.48%
7	**TSS**	$ 597	$ 441	$ 80	13.41%	$ 352	$ 89	$ (22)	$ 35	$ 13	$ 549	**2.3%**	14.69%
8	**ALS, SLS**	$ 270,354	$ 84,745	$ 35,130	12.99%	$ 46,103	$ 38,642	$ (9,661)	$ 15,887	$ 6,227	$ 88,103	**7.1%**	14.39%
9	**SFL**	$ 1,009	$ 180	$ 8	0.80%	$ 231	$ (51)	$ 13	$ 59	$ 72	$ 192	**37.6%**	5.26%
	TOTAL RETAIL	**$ 8,125,592**	**$ 2,982,637**	**$ 324,867**	**4.00%**	**$ 2,982,637**	**$ (0)**	**$ 0**	**$ 477,495**	**$ 477,495**	**$ 3,209,189**	**14.9%**	**7.66%**

Calculations for Rate Design in Order to Apply Increase to Unadjusted Billing Determinents

Line No.	Rate Class	Proposed Rate Increase After Reduction in Variance (M)	Customer Growth Adjustment in Present Revenues (N)	Weather Normalization Adjustment in Present Revenues (O)	Matthew Revenue Adjustment in Present Revenues (P)	Total Adjustments to Exclude for Rate Design (Q)	Ratio of Unadjusted Present Revenues to Adjusted (R)	Target Revenue Increase for Rate Design (to be applied to unadjusted billing determinents) (S)	Total Unadjusted Revenue with Clauses & REPS at Current Rates (T)	Proposed Percent Increase to unadjusted Revenues for Rate Design (U)
		(I)				(N) + (O) + (P)	[(B) - (Q)] / (B)	(M) x (R)		(S) / (T)
10	**RES**	$ 243,306	$ 6,843	$ 701	$ 6,759	$ 14,304	99.014%	240,906	1,584,289	**15.2%**
11	**SGS**	$ 26,516	$ 829	$ (2,196)	$ 800	$ (568)	100.304%	26,596	216,085	**12.3%**
12	**SGSCLR**	$ 11	$ 27	$ (33)	$ 12	$ 6	99.784%	11	3,589	**0.3%**
13	**MGS**	$ 130,829	$ 1,955	$ (8,900)	$ 3,918	$ (3,027)	100.383%	131,330	823,865	**15.9%**
14	**LGS**	$ 68,756	$ 976	$ (4,093)	$ 497	$ (2,620)	100.568%	69,146	477,750	**14.5%**
15	**SI**	$ 1,766	$ -	$ -	$ 23	$ 23	99.566%	1,759	5,452	**32.3%**
16	**TSS**	$ 13	$ (10)	$ -	$ 0	$ (10)	102.226%	13	562	**2.3%**
17	**ALS, SLS**	$ 6,227	$ 142	$ -	$ 129	$ 271	99.680%	6,207	87,820	**7.1%**
18	**SFL**	$ 72	$ (4)	$ -	$ 1	$ (3)	101.937%	73	195	**37.6%**
	TOTAL RETAIL	**$ 477,495**	**$ 10,758**	**$ (14,521)**	**$ 12,139**	**$ 8,376**	**99.719%**	**$ 476,042**	**$ 3,199,609**	**14.9%**